Canadian Utilities Limited / 1976 Annual Report

Contents

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PHILIP HINDMARCH

DIRECTOR OF PUBLIC RELATIONS
CANADIAN UTILITIES LIMITED

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EDMONTON, ALBERTA
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Highlights

	1976	1975	Increase
Revenues (thousands)			
Natural Gas	**$217,732**	$142,436	$ 75,296
Electric	**78,133**	57,945	20,188
Total	**$295,865**	$200,381	$ 95,484
Net earnings from operations (thousands)	**$ 27,491**	$ 23,865	$ 3,626
Fully diluted earnings per common share*	**$ 1.55**	$ 1.45	$ .10
Dividends paid			
on common shares (thousands)	**$ 11,014**	$ 7,142	$ 3,872
per share	**$ .765**	$ .65	$ .115
Capital expenditures (thousands)	**$ 86,354**	$ 80,669	$ 5,685
Customers at year-end			
Natural Gas	**400,474**	373,254	27,220
Electric	**99,629**	94,040	5,589

**Does not include a non-recurring gain of $2,329,000 or $.16 per share in 1975, a result of the sale of property.*

The company's electric sales in 1976 were 2,182 million kilowatt hours, nearly eight per cent higher than in 1975. Peak load increased to 455 megawatts, up 10 megawatts over the previous year.

During the year the company's natural gas utilities installed more than 1,400 miles of new transmission and distribution line such as the 20-inch diameter pipe shown below.

To the Shareholders:

This year's report will give you a description of Canadian Utilities at the completion of its first five years of operation after being restructured to bring together, in one company, major interests in both the natural gas and electric businesses. It is interesting to note, though, that it is also the 50th annual report published by this company since it was originally formed to operate a number of small electric utility properties.

Canadian Utilities Limited achieved several new records in 1976: Net earnings from operations ($1.55 a share) reached an all-time high; the company paid record common share dividends; and major outlays for new facilities gave rise to unprecedented levels of external debt and equity financing. Also, the company's utility operations have recently surpassed the half-million mark in number of customers served.

For the second consecutive year an issue of common shares was made to the Canadian public. In November the sale of two million shares at $12.25 a share provided net proceeds of $23 million and added over 2,000 new shareholders, many of whom reside in Alberta and are customers of one or more of the subsidiaries supplying gas and electric utility service in the province. At the end of 1976 the company had 5,867 common shareholders, distributed as follows:

Alberta residents	2,725
Other Canadian residents	3,089
Shareholders outside Canada	53
Total number of shareholders	5,867

The increased number of common shares available for trading and the larger base of shareholders should ensure a ready market for the shares at values that will not be inhibited by limited trading volumes.

In the five-year period just completed it has been necessary to raise both electric and gas utility rates a number of times, but the increases have been essential to discharge the company's obligations to meet the growing demand for utility services.

During the five years, net assets (all assets less current liabilities) have doubled from $286 million to $569 million, and earnings from operations available to common and convertible preferred shareholders have increased 65 per cent from $14.6 million in 1972 to $24.1 million. However, in terms of dollars invested in the company by the common and convertible preferred shareholder, earnings per dollar involved were about the same in 1976 as they were in 1972 — 14 cents per dollar invested.

In 1976, for every dollar of revenue received, about 47 cents was used to purchase natural gas and coal; 11 cents was paid directly to various levels of government as taxes and royalties; 26 cents to cover labor and other costs of operation; and eight cents to pay interest and dividends to those who have supplied the company with debt and preferred equity capital. Of the remaining eight cents of the revenue dollar, about one-half was paid to the common shareholders as dividends and the balance reinvested in the business.

All together, three external financings totalling $114.5 million were made to the Canadian public during the year. In addition to the common share issue mentioned above there was a $50 million issue of 11¼ per cent Debentures 1976 Series, the largest financing ever made by the company. In December the company issued $40 million in 9.24 per cent Series B preferred shares. The ability to continue financings as successfully as this is dependent to a large degree on the responsiveness of the regulatory process in Alberta, the principal jurisdiction in which the company operates. During a period of rapidly escalating costs of service, prompt adjustments in rates have been absolutely vital, especially when common dividends and reinvested earnings together represent only eight cents of the revenue dollar.

The fourth quarter common share dividend was increased from 18½ cents to 21 cents to maintain a policy of distributing slightly more than one-half of the earnings available to common shareholders and, if possible, of adjusting the dividend rate each year to accomplish that goal.

We were pleased to welcome as a director, Robert F. Calman, who was elected at our 1976 annual shareholders' meeting.

Later in the year, on December 8, 1976, the services of a valuable and much respected director were lost with the death of Frederick T. Jenner. His significant contributions as a member of the Board and chairman of our audit committee will be gratefully remembered. We regret to report the death, also in December, of a former director, Kenneth L. MacFadyen, who had served both as a director and a senior officer of the company and its subsidiaries until his retirement in 1973.

For the past 20 years we have enjoyed the assistance and encouragement of F. Clarence Manning in his role as a director of several of our companies, and more recently as an Honorary Director of Canadian Utilities. As of this year's annual meeting, he will no longer be eligible for reappointment as an Honorary Director, having attained the company's mandatory retirement age.

The planning for, and provision of, reliable utility service in the fast growing Alberta economy during a period of rising costs places heavy demands on all employees. We are fortunate to have in the organization dedicated and competent men and women prepared to meet the escalating growth and opportunities expected in Alberta over the next few years.

On behalf of the Board of Directors

E. W. King

E. W. King, President

J. E. Maybin

J. E. Maybin, Chairman

February 10, 1977.

Below, a Northwestern Utilities crew installs a distribution line to provide additional natural gas capacity for Edmonton's business area.

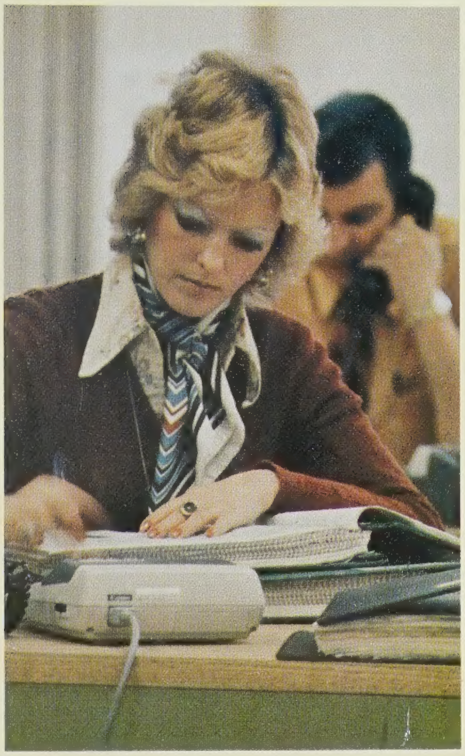
Corporate Structure

Canadian Utilities Limited

- **Electric Utility**
  - Alberta Power Limited
    - The Yukon Electrical Company Limited
    - Yukon Hydro Company Limited
- **Gas Utility**
  - Canadian Western Natural Gas Company Limited
- **Gas Utility**
  - Northwestern Utilities Limited
    - Northland Utilities (B.C.) Limited
- **Engineering Services**
  - CU Engineering Limited
- **Petrochemical Feedstocks**
  - CU Ethane Limited
- **Resource Development**
  - CU Resources Limited

At the end of 1976 Canadian Utilities and subsidiaries employed over 3,000 men and women, mainly in Alberta, but also in the Yukon, the Northwest Territories, British Columbia and Ontario.

Financial Review



Summary

Each of the regulated utility subsidiaries filed new rate applications during the year to obtain sufficient revenues to match the rapidly increasing cost of service.

The seven per cent growth in operating earnings from $1.45 to $1.55 only partially reflects the growth in average shareholder investment and the ability to issue new common shares at values that do not dilute per share equity investment accruing to existing shareholders. Abnormally warm weather conditions in Alberta unfavourably affected earnings from the natural gas utilities.

Of particular significance was the very substantial strengthening of the financial position of the company as a result of a major financing program involving new issues of long-term debt and equity with a total value in excess of $114 million.

Rate Applications and Cost of Service

The Public Utilities Board of Alberta will, upon application, consider a request for a rate increase to take effect on an interim, refundable basis,

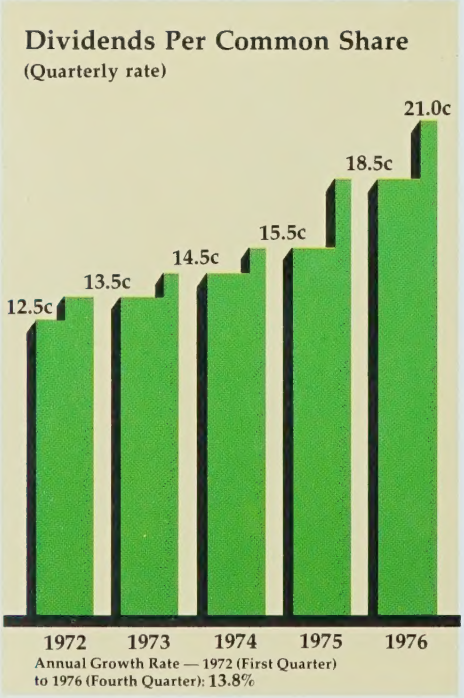
	Date	Rate Base $ Million	Return on Rate Base	Implied Equity Rate of Return	Test Year
Alberta Power Limited					
Latest final order	Nov./76	255.4	10.4%	14.4%	1976
Canadian Western Natural Gas Company Limited					
Latest final order	Jan./77	91.0	10.6%	14.7%	1976
Interim	Dec./76	105.4	10.9%	14.6%	1977
Northwestern Utilities Limited					
Latest final order	Sept./76	106.2	10.0%	14.3%	1975
Interim	Apr./76	119.2	10.7%	14.7%	1976
Interim	Dec./76	136.3	10.9%	14.7%	1977

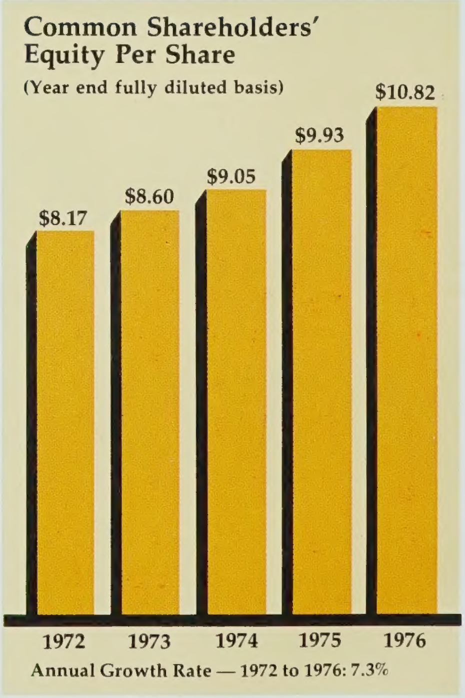
preceding the rather lengthy period that elapses before a final decision is made on the merits of each case. This feature of the regulatory practice in Alberta is of particular importance when costs incurred by the company are rising rapidly and the size and timing of increases are difficult to anticipate. While most of the revenues collected by interim rates have subsequently been confirmed, refunds to consumers were recorded in the year of about $2 million in total — ordered in a final decision on the 1976 test year by Alberta Power Limited, and on two final decisions received by Canadian Western Natural Gas Company Limited on the test years 1975 and 1976. In each of these decisions, the rate of return on common equity requested was confirmed in determining the utility revenue requirements.

Earnings

In 1976, net earnings from operations available to common and $1.25 Convertible Preferred shareholders rose over the previous year by 18 per cent to $24.1 million, maintaining the rate of increase experienced in the five-year period since the restructuring of the companies to the present corporate form. Earnings from natural gas utility operations were restricted by above normal weather conditions during the year, whereas near normal temperatures were experienced in 1975. A growth of three per cent in volume of gas sold in the year compares to an estimated growth of eight per cent that would have occurred under normal weather conditions.

The average number of common shares in 1976 on a fully diluted basis was 15,567,310, nine per cent above the 1975 figure of 14,258,136. Earnings per share from operations of $1.55 were seven per cent above the $1.45 recorded in 1975. In the five years from 1972 to 1976 inclusive, earnings per share have grown at a compound rate of 10 per cent.



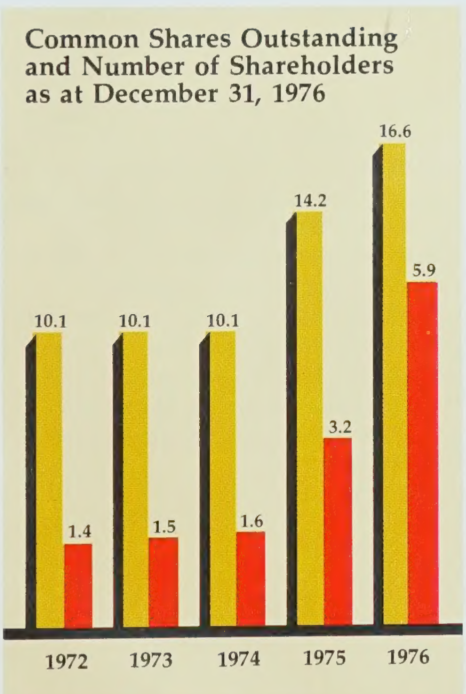


Earnings Summary

	1976	1975	1974	1973	1972	5-Year Rate of Growth
			(Millions of dollars)			
Electric	**15.8**	13.6	7.6	7.5	7.4	21.2
Gas	**12.5**	10.9	8.2	8.0	8.6	9.0
Other	**0.1**	0.2	0.3	(0.3)	0.1	
	28.4	24.7	16.1	15.2	16.1	
Less:						
Preferred dividends	**3.4**	3.3	0.5	0.5	0.5	
Preferred dividends paid to minority shareholders	**0.9**	0.9	0.9	0.9	1.0	
Net earnings from operations available to common and $1.25 convertible preferred shareholders	**24.1**	20.5	14.7	13.8	14.6	14.3

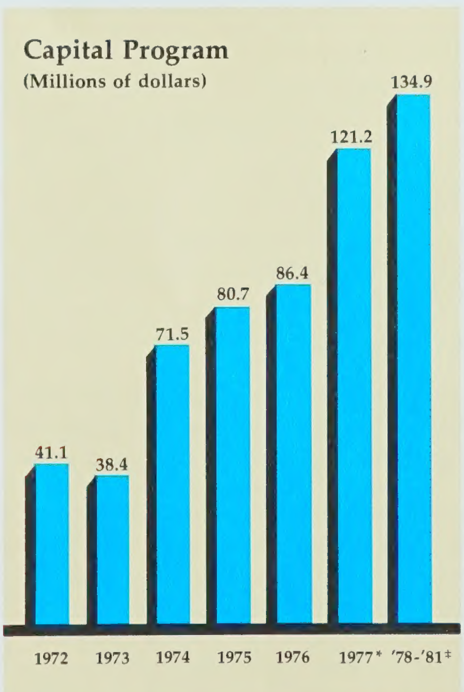
Capitalization and New Financing

A program to lessen the dependence on debt financing was continued in the year. Debt in the form of notes payable, bonds and debentures, which represented 61 per cent of invested capital at the close of 1974, was reduced to 45 per cent at the close of 1976. A $50 million issue of debentures to the public in early 1976 primarily displaced notes payable.

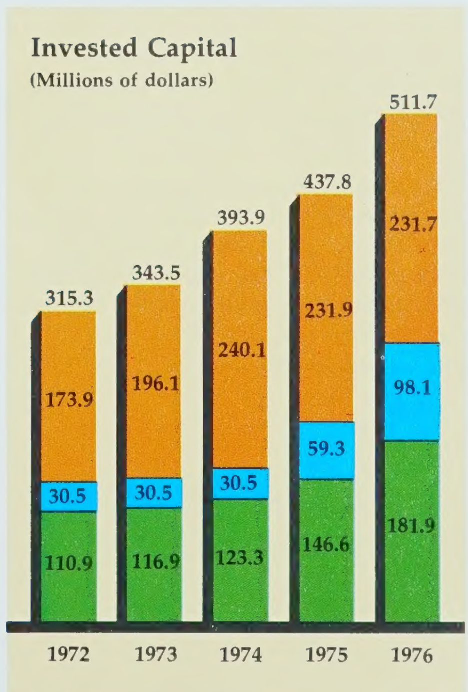


Number of shares outstanding in millions

Number of shareholders in thousands



* Estimated capital expenditures
‡ Estimated average annual capital expenditures

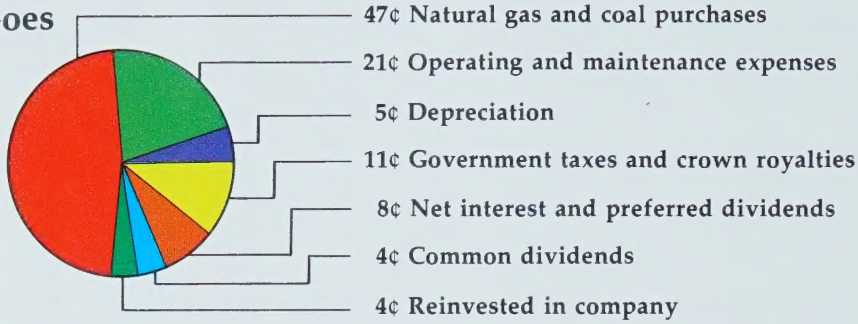


Notes payable and long-term debt

Preferred equity including minority interest

Common equity including $1.25 convertible preferred

Where the Sales Dollar Goes



Two equity offerings were made to the Canadian public during the year. Proceeds from an issue of two million common shares, at a price of $12.25 per share, were received in November and proceeds from a $40 million issue of preferred shares were received in December. As a result of this financing program the company is better prepared to manage the acceleration in capital expenditures expected in the balance of this decade.

The book value of the equity per common share at the close of the year was $10.82, an increase of nine per cent over 1975. The issue of common shares in 1976 provided sufficient net proceeds to avoid dilution of shareholders' book value.

A long-term objective to improve the distribution of common shares and their availability for trade was achieved in 1976. At the close of the year 16.6 million common shares were outstanding, an increase of 6.5 million shares or 65 per cent in the two-year period from the close of 1974. In addition to the issue to the public in Canada of 3.1 million shares, another 3.4 million shares were issued in the last two years upon conversion of $1.25 convertible preferred shares. The company exercised its option and redeemed the remaining convertible preferred shares outstanding on January 28, 1977.

Income Taxes

The regulated utility subsidiaries are permitted to recover income taxes currently paid as determined on a basis that minimizes payments through claiming maximum amounts for capital cost allowances. In this manner, $60 million of income taxes have been deferred and will be recovered from customers at a future date. Present legislation in Alberta, in effect, provides for a return to utility customers of income taxes paid by the utility company. The effective rate of tax for 1976 was 23 per cent as compared to 26 per cent in 1975.

Pension Commitments

An actuarial review of the pension plan in effect in the company indicated an experience deficiency in the plan of $9.1 million that, under existing Alberta legislation, is required to be amortized over a period not exceeding five years. The deficiency has resulted from lower than assumed earnings in the fund due to weak capital markets in the three-year period since the previous review. Another factor has been a higher than expected level of inflation pushing wages and salaries to levels in excess of those forecast. An additional unfunded liability of $5.7 million was previously recognized and is being amortized. Future applications to the Public Utilities Board will include amounts appropriate to meet these obligations.

Assets and Capital Expenditures

Total assets at the close of 1976 were $644 million compared to $574 million in 1975. Capital expenditures in 1976 of $86 million included significant outlays for gas transmission facilities that raised the amount of spending by the gas utilities to a record $40 million. The 1977 program is expected to require total expenditures of $121 million, including about $19 million for construction of an ethane plant to be jointly owned with Dome Petroleum Limited. In the years 1978 to 1981 inclusive, average annual capital expenditures of $135 million are forecast. A major project scheduled for the period is construction of a 375-megawatt addition to the Battle River thermal generating station.

Government of Alberta Natural Gas Rebates Plan

Approximately $60 million was received by the company from the Alberta government in each of 1976 and 1975 under a program to partially shield consumers from the rapid rise in the field price of natural gas in the province. The rebate in 1976 represented 30 per cent of the cost of gas purchased by the company, compared to 46 per cent a year earlier when prevailing prices were lower.

Dividend Policy

In 1976, the quarterly dividend on the company's common stock was increased from 18.5 cents to 21 cents per share effective with the December 1st payment. This action raised the indicated annual rate from 74 cents to 84 cents and represented 54 per cent of the net earnings available for distribution in the year. The company has been following, and hopes to continue, a policy of increasing the dividend during each year so that the annualized amount of the final quarterly dividend represents at least 50 per cent of net earnings from operations available for payout to common shareholders. Dividend payments on the common stock during fiscal 1976 and 1975 were:

	Cents per Share	
Payment Date	**1976**	1975
March 1	**18.5**	15.5
June 1	**18.5**	15.5
September 1	**18.5**	15.5
December 1	**21.0**	18.5

The increases in the dividends paid in the fourth quarters of 1976 and 1975 were approved by the Anti-Inflation Board.

Consolidated Statement of Earnings

Year ended December 31, 1976 with comparative figures for 1975

	Thousands 1976	1975
NATURAL GAS REVENUES	**$217,732**	$142,436
ELECTRIC REVENUES	**78,133**	57,945
	295,865	200,381
OPERATING EXPENSES (NOTE 1)		
Natural gas supply (Net of Alberta government rebate)	**134,679**	70,852
Operating and maintenance	**72,797**	56,541
Taxes — other than income	**17,013**	11,804
Depreciation	**15,648**	13,293
	240,137	152,490
OPERATING INCOME	**55,728**	47,891
OTHER INCOME		
Interest capitalized during construction	**1,304**	4,022
Interest and dividends	**764**	417
Gain on purchase of long-term debt	**532**	405
Miscellaneous	**935**	527
	3,535	5,371
	59,263	53,262
INCOME DEDUCTIONS		
Interest on long-term debt	**19,617**	15,446
Interest on loan from affiliated company	**263**	263
Other interest	**1,978**	3,852
Debt and share expenses amortized	**387**	290
	22,245	19,851
	37,018	33,411
INCOME TAXES (NOTE 2)	**8,667**	8,686
	28,351	24,725
MINORITY INTERESTS	**860**	860
NET EARNINGS BEFORE EXTRAORDINARY ITEM	**27,491**	23,865
EXTRAORDINARY ITEM — NON-RECURRING GAIN (NOTE 3)		2,329
NET EARNINGS	**$ 27,491**	$ 26,194
EARNINGS — DOLLARS PER COMMON SHARE (NOTE 4)		
Basic		
Net earnings before extraordinary item	**$ 1.62**	$ 1.69
Extraordinary item — non-recurring gain		.21
Net earnings	**$ 1.62**	$ 1.90
Fully diluted		
Net earnings before extraordinary item	**$ 1.55**	$ 1.45
Extraordinary item — non-recurring gain		.16
Net earnings	**$ 1.55**	$ 1.61

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Consolidated Balance Sheet

December 31, 1976 with comparative figures for 1975

	Thousands 1976	1975
ASSETS		
CURRENT ASSETS		
Cash	$ 311	$ 265
Short-term investments	20,600	100
Accounts receivable (Note 5)	42,813	61,885
Materials and supplies — at average cost	8,552	10,078
Natural gas stored at cost	4,552	2,474
Prepaid expenses (Note 6)	3,520	4,112
	80,348	78,914
TRUST ASSETS HELD FOR RURAL COOPERATIVE LINES, PER CONTRA	7,266	6,726
TRUST ASSETS HELD FOR INCOME TAX REBATE FOR CONSUMERS, PER CONTRA	5,043	3,056
ACCOUNTS RECEIVABLE DUE BEYOND ONE YEAR	904	1,051
PROPERTY, PLANT AND EQUIPMENT AT COST (NOTE 7)	688,616	611,158
Accumulated depreciation	146,354	135,042
	542,262	476,116
DEFERRED EXPENSES UNAMORTIZED (NOTE 8)	8,522	8,003
	$644,345	$573,866
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Due to bank	$ 4,257	$ 4,124
Accounts payable and accrued liabilities	56,718	63,212
Dividends payable	1,029	1,015
Long-term debt — current maturities (Note 11)	2,829	11,578
Preferred shares to be redeemed (Note 13)	1,200	1,200
Deposits	2,504	1,742
Income and other taxes	7,132	12,969
	75,669	95,840
AMOUNTS HELD IN TRUST, PER CONTRAS	12,309	9,782
MISCELLANEOUS LIABILITIES (NOTE 9)	4,788	1,394
NOTES PAYABLE (NOTE 10)	2,400	47,275
NOTE PAYABLE TO AFFILIATED COMPANY, 7½%, due November 15, 1978	3,500	3,500
LONG-TERM DEBT (NOTE 11)	225,734	181,068
DEFERRED INCOME TAXES (NOTE 2)	60	954
CONTRIBUTIONS FOR EXTENSIONS TO PLANT	37,826	27,641
AMOUNT RECEIVED UNDER THE NATURAL GAS PRICING AGREEMENT ACT	2,035	478
MINORITY INTERESTS (NOTE 12)	20,008	20,008
SHAREHOLDERS' EQUITY (NOTE 11)		
Preferred shares (Note 13)	78,978	44,526
Common shares (Note 14)	134,684	105,833
	213,662	150,359
Less excess cost of shares of subsidiary companies over underlying net book value at December 31, 1971	17,567	17,567
	196,095	132,792
Retained earnings	63,921	53,134
	260,016	185,926
	$644,345	$573,866

On behalf of the Board:

J. E. Maybin/Director **D. R. B. McArthur**/Director

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Consolidated Statement of Changes in Financial Position

Year ended December 31, 1976 with comparative figures for 1975

	Thousands 1976	1975
SOURCES OF WORKING CAPITAL		
Net earnings before extraordinary item	**$ 27,491**	$ 23,865
Add non-cash items, principally depreciation	**17,051**	14,729
Provided from operations	**44,542**	38,594
Increase in notes payable		5,197
Issue of long-term debt	**48,996**	
Issue of $10^1/_4$% cumulative redeemable second preferred shares Series A		28,973
Issue of 9.24% cumulative redeemable second preferred shares Series B	**38,775**	
Issue of common shares	**23,089**	9,465
Issue of common shares on conversion of $1.25 preferred shares	**4,348**	30,229
Increase in contributions for extensions to plant	**11,375**	9,916
Disposition of property, plant and equipment	**3,453**	2,527
Extraordinary disposition of property, plant and equipment		2,572
Amount payable for coal leases	**3,000**	
Net proceeds under The Natural Gas Pricing Agreement Act	**1,557**	478
Other	**202**	263
	179,337	128,214
USES OF WORKING CAPITAL		
Purchase of property, plant and equipment	**86,354**	80,669
Reduction in notes payable	**44,875**	
Reduction in long-term debt	**5,334**	13,467
Redemption of preferred shares	**1,200**	1,200
Dividends paid — preferred	**3,631**	5,075
— common	**11,014**	7,142
Preferred dividends declared in advance	**75**	141
Conversion of $1.25 preferred shares	**4,348**	30,229
Increase in deferred expenses	**901**	1,282
	157,732	139,205
INCREASE (DECREASE) IN WORKING CAPITAL	**$ 21,605**	$(10,991)
ANALYSIS OF CHANGES IN WORKING CAPITAL		
Cash	**$ 46**	$ 229
Short-term investments	**20,500**	100
Marketable securities		(522)
Accounts receivable	**(19,072)**	28,637
Materials and supplies	**(1,526)**	532
Natural gas stored	**2,078**	896
Prepaid expenses	**(592)**	2,413
Total	**1,434**	32,285
Due to bank	**133**	(1,933)
Accounts payable and accrued liabilities	**(6,494)**	26,008
Dividends payable	**14**	1,015
Long-term debt — current maturities	**(8,749)**	7,326
Preferred shares to be redeemed		1,200
Deposits	**762**	221
Income and other taxes	**(5,837)**	9,439
Total	**(20,171)**	43,276
INCREASE (DECREASE) IN WORKING CAPITAL	**$ 21,605**	$(10,991)

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Consolidated Statement of Retained Earnings

Year ended December 31, 1976 with comparative figures for 1975

	Thousands 1976	1975
BALANCE AT BEGINNING OF YEAR	**$53,134**	$40,009
ADD NET EARNINGS	**27,491**	26,194
	80,625	66,203
DEDUCT		
Dividends		
Preferred shares	**3,426**	3,374
$1.25 cumulative redeemable convertible preferred shares	**205**	1,701
Common shares	**11,014**	7,142
	14,645	12,217
Preferred dividends declared in advance	**75**	141
Share issue expense less related income taxes	**1,984**	711
	16,704	13,069
BALANCE AT END OF YEAR	**$63,921**	$53,134

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

Summary of Significant Accounting Policies

Basis of consolidation

The consolidated financial statements include the accounts of the company and all subsidiary companies. All material inter-company balances and transactions have been eliminated.

Property, plant and equipment

Property, plant and equipment includes cost of land, buildings and equipment. Certain additions to property, plant and equipment are made with the assistance of provincial government grants and cash contributions from the customers who are to be served by the specific additions. Such contributions are required where the estimated revenue, over a specific period of time, is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. The gross cost of additions including any allowance for funds used during construction is included in property, plant and equipment.

Depreciation is provided on pooled assets at composite rates on a straight-line basis over the average estimated useful lives of the assets. Effective rates of depreciation are approximately three per cent per annum after giving effect to contributions for extensions to plant in accordance with the orders of regulatory bodies.

Certain resource properties are depreciated in part on a unit withdrawal basis.

On retirement of depreciable plant, the accumulated depreciation is charged with the cost of the retirement unit less net salvage. Gains and losses on extraordinary retirements are recognized as extraordinary items in the financial statements.

Interest capitalized during construction.

An allowance for funds used during construction of electric plant is capitalized at the weighted average interest rate of long-term debt.

Deferred expenses unamortized

Expenses incurred in connection with the issue of long-term debt and preferred shares subject to mandatory redemption are amortized over the periods that the debt and shares are outstanding.

The company became a participant in the Gas Arctic-Northwest Project Study Group on September 26, 1973. Following a decision of the Public Utilities Board of Alberta that Canadian Western Natural Gas Company Limited could not include the costs of its participation in the calculation of its rate base, the company withdrew from the group on May 31, 1975. Subsequently the Board made a similar decision with respect to Northwestern Utilities Limited.

These costs have been deferred until the feasibility of the project has been determined and the necessary regulatory approvals obtained. If the project is approved by the National Energy Board and other regulatory bodies, the group agreement provides that the participants, including participants which have withdrawn from the group, will sell the information and knowledge resulting from the study to one or more pipeline companies incorporated for the purpose of implementing the project for a price at least equal to the costs incurred and also provides that they shall have an opportunity to acquire an equity interest in the pipeline companies. In the event the project does not proceed, costs not recovered will be written off in the statement of earnings.

Deferred charges relating to gas exploration include expenditures related to the development of gas reserves. Costs resulting in a successful venture are capitalized and depreciated on a unit withdrawal method. The Public Utilities Board of Alberta has directed that the costs of unsuccessful exploration expense, net of income taxes, will be charged against the amounts received under the Natural Gas Pricing Agreement Act.

Goodwill consists of the excess cost of shares issued over the underlying net book value of shares acquired in 1972 from minority shareholders of a subsidiary company and is being amortized over a period of 40 years.

Other deferred charges are subject to amortization over varying periods of time not exceeding 40 years.

Income taxes

In fixing rates, except for the matters referred to below, the Public Utilities Board of Alberta permits the utility companies to recover only taxes payable currently and, accordingly, to the extent that capital cost allowances are claimed in excess of recorded depreciation, there has been a related reduction in the amount of income taxes otherwise payable which has not been reflected in the financial statements.

The reduction will become a charge to be borne by the consumer in future years when recorded depreciation exceeds capital cost allowances claimed for income tax purposes.

The companies are permitted to claim deferred income taxes in respect to acquisition of natural gas rights, expenses in connection with the Gas-Arctic-Northwest Project Study Group, deferred gas costs, rate case expenses and share issue costs. The gas subsidiaries, at the specific request of the major communities served, have agreed to amortize the deferred taxes in respect to acquisition of natural gas rights by reducing the annual provisions for income taxes over a ten-year period.

Amounts received under The Natural Gas Pricing Agreement Act

Under The Natural Gas Pricing Agreement Act the company as an Alberta gas producer has received a pro rata share of monies available under the Act which have been recorded net of royalties and income taxes. It is the company's intention, subject to approval of the Public Utilities Board of Alberta, to charge the costs of unsuccessful exploration against these amounts.

Natural gas supply

The Province of Alberta enacted The Natural Gas Rebates Act effective January 1, 1974 to shelter the majority of Alberta natural gas consumers from the full impact of significant price increases for natural gas. Under the provisions of the Act, the gas utilities are reimbursed for the excess price paid to their suppliers over the support price. The statement of earnings is charged with the net cost of natural gas.

Notes to Financial Statements

December 31, 1976

1. Operating expenses

	1976		1975	
	Natural Gas	Electric	Natural Gas	Electric
	(Thousands)		(Thousands)	
Natural gas supply:				
Gross cost of natural gas purchased	$193,630		$131,398	
Alberta government rebate	58,951		60,546	
Net cost of natural gas purchased	134,679		70,852	
Operating and maintenance	35,816	$36,981	31,434	$25,107
Taxes — other than income	14,334	2,679	9,601	2,203
Depreciation	6,748	8,900	6,931	6,362
	$191,577	$48,560	$118,818	$33,672
Total	$240,137		$152,490	

2. Income taxes

The provision for income taxes in the consolidated statement of earnings includes a deferred tax draw-down of $912,000 in 1976 (a deferred tax provision of $1,321,000 in 1975).

Total deferred income taxes increased by $21,274,000 during 1976 ($7,706,000 in 1975). The cumulative amount of deferred income taxes to December 31, 1976 is $59,953,000 of which $60,000 has been recorded in the accounts as a deferred credit, $1,791,000 as a reduction in deferred expenses and $845,000 is included in income and other taxes payable.

The above increase in total deferred income taxes includes $261,000 relating to 1975 and $15,334,000 relating to prior years not previously noted as unrecorded deferred income taxes.

3. Extraordinary item

The extraordinary item amounting to $2,329,000 in 1975, net of income taxes of $418,000, represents a non-recurring gain from the sale of property.

4. Earnings per common share

In the fully diluted earnings per common share calculation, the assumption is made that warrants for the purchase of common shares at $9 had been exercised at the beginning of each year and that the funds derived therefrom had been invested to produce an annual rate of 8% before applicable income taxes. In addition, the calculation assumes conversion of the convertible preferred shares at the beginning of each year.

5. Accounts receivable

	1976	1975
	(Thousands)	
Consumer accounts, gas and electric	$26,744	$31,300
Receivable from the Province of Alberta under The Natural Gas Rebates Act		13,321
Receivable from the Province of Alberta under The Natural Gas Pricing Agreement Act	6,505	
Other receivables and deposits	9,564	17,264
Balance at end of year	$42,813	$61,885

6. Prepaid expenses

	1976	1975
	(Thousands)	
Deferred purchase gas supply costs	**$ 1,798**	$ 3,301
Other	**1,722**	811
Balance at end of year	**$ 3,520**	$ 4,112

7. Property, plant and equipment

	1976		1975	
	Cost	**Accumulated Depreciation**	Cost	Accumulated Depreciation
	(Thousands)		(Thousands)	
Gas utility plant and equipment	**$327,177**	**$ 93,163**	$293,058	$ 89,365
Electric utility plant and equipment	**351,645**	**53,191**	308,621	45,677
Undertakings, franchise and gas rights	**8,000**		8,000	
Land	**1,794**		1,479	
Balance at end of year	**$688,616**	**$146,354**	$611,158	$135,042

8. Deferred expenses unamortized

	1976	1975
	(Thousands)	
Unamortized debt discount and expense	**$ 3,991**	$ 3,327
Unamortized preferred share issue expense	**986**	1,027
Expenditures in Gas Arctic-Northwest Project Study Group (net of accumulated deferred taxes of $1,515,000 at December 31, 1976 and $1,515,000 at December 31, 1975)	**1,598**	1,659
Goodwill	**504**	518
Other deferred charges Unamortized expense incurred in connection with corporate reorganization, gas exploration and utility rate hearings (net of accumulated deferred taxes of $276,000 at December 31, 1976 and $167,000 at December 31, 1975)	**1,443**	1,472
Balance at end of year	**$ 8,522**	$ 8,003

9. Miscellaneous liabilities

	1976	1975
	(Thousands)	
Coal leases	**$ 3,000**	$
Other	**1,788**	1,394
Balance at end of year	**$ 4,788**	$ 1,394

10. Notes payable

In common with most public utilities, the company is required to obtain new capital by issues of debentures and capital stock in order to finance its construction and expansion program. To permit the company to time the issues most advantageously, the company has entered into a loan agreement with its bankers under which they are committed until March 14, 1978 to loan the company on demand up to $60,000,000. The company issues commercial paper relying upon this commitment and, accordingly, at December 31, 1976 notes payable of $2,400,000 representing commercial paper with maturities to January 13, 1977 have been classified as long-term debt.

11. Long-term debt

	Total	Current Maturities
	(Thousands)	
Canadian Utilities Limited:		
$8^3/_8$% debentures 1972 Series, due March 1, 1992	$ 28,070	
$8^3/_4$% debentures 1973 Series, due July 2, 1993	15,000	$ 882
$9^1/_8$% debentures 1974 Series, due March 15, 1994	15,000	
$11^1/_2$% debentures 1974 - 2nd Series, due October 1, 1994	17,500	
$11^1/_4$% debentures 1976 Series, due February 15, 1996	50,000	
	125,570	882
Alberta Power Limited:		
First mortgage sinking fund bonds:		
Series D — $4^1/_4$%, due November 1, 1979	3,320	40
Series E — $4^1/_8$%, due April 1, 1981	2,914	
Series F — $5^1/_2$%, due December 1, 1986	5,000	
Series G — $5^5/_8$%, due June 1, 1990	12,000	
Series H — $6^1/_2$%, due February 1, 1992	8,000	
Sinking fund debentures:		
Series A — $7^1/_4$%, due May 15, 1988	13,475	
Series B — $9^5/_8$%, due December 15, 1991	8,458	58
	53,167	98
Canadian Western Natural Gas Company Limited:		
First mortgage sinking fund bonds:		
Series B — $5^3/_4$%, due February 1, 1982	3,488	
Series C — $5^3/_8$%, due April 1, 1983	2,431	
Series D — $5^5/_8$%, due May 1, 1989	3,625	125
Series E — 7%, due June 15, 1992	5,600	175
Sinking fund debentures:		
$9^3/_4$%, due December 1, 1990	8,493	368
	$ 23,637	$ 668

Northwestern Utilities Limited:		
First mortgage sinking fund bonds:		
Series F — $4^{3}/_{4}$%, due January 15, 1979	**$ 715**	$ 238
Series G — $5^{3}/_{8}$%, due April 15, 1983	**3,678**	
Series H — $5^{3}/_{4}$%, due March 1, 1988	**7,486**	
Series I — $6^{1}/_{2}$%, due May 1, 1992	**3,830**	130
Series J — $9^{3}/_{4}$%, due December 15, 1994	**6,526**	190
Sinking fund debentures:		
Series C — $6^{3}/_{4}$%, due May 1, 1977	**517**	517
Series D — $6^{3}/_{4}$%, due December 1, 1978	**519**	
Series E — $7^{1}/_{4}$%, due October 15, 1985	**2,918**	106
	26,189	1,181
Total long-term debt	**228,563**	$ 2,829
Deduct current maturities	**2,829**	
Long-term debt less current maturities	**$225,734**	

The long-term debt outstanding and current maturities thereof are stated after deducting bonds and debentures which have been purchased by the company and are held for future sinking fund payments and excluding requirements which may be satisfied by certification of property additions.

Installments of long-term debt maturing in each of the calendar years 1977, 1978, 1979, 1980 and 1981 amount to $2,829,000, $6,096,000, $9,378,500, $5,900,000 and $8,710,000 respectively. These maturities exclude requirements which may be satisfied by certificates of property additions and after deducting bonds and debentures which have been repurchased.

The bond and debenture indentures executed by the company and its subsidiaries place limitations on the company and its subsidiaries, including restrictions on the payment of dividends. Of the consolidated retained earnings at December 31, 1976 and 1975, approximately $36,860,000 and $28,243,000 respectively were free from such restrictions.

12. Minority interests

		(Thousands)
Northwestern Utilities:		
105,000 4% Cumulative Redeemable Preference Shares of the par value of $100 each		$10,500
Canadian Western Natural Gas Company Limited:		
275,410 4% Cumulative Redeemable Preference Shares of the par value of $20 each	$5,508	
200,000 $5^{1}/_{2}$% Cumulative Redeemable Preference Shares of the par value of $20 each	4,000	9,508
		$20,008

13. Preferred shares

Authorized:

40,000 5% Cumulative Redeemable Preferred Shares of the par value of $100 each.

150,000 series preferred shares of the par value of $100 each, issuable in series, of which 15,000 shares have been designated as Cumulative Redeemable Preferred Shares 4¼% Series and 50,000 shares designated as Cumulative Redeemable Preferred Shares 6% Series.

4,000,000 series second preferred shares of the par value of $25 each, issuable in series, authorized May 16, 1974, of which 1,200,000 shares have been designated as 10¼% Cumulative Redeemable Second Preferred Shares Series A and 1,600,000 shares have been designated as 9.24% Cumulative Redeemable Second Preferred Shares Series B.

1,780,000 $1.25 Cumulative Redeemable Convertible Preferred Shares of the par value of $20 each.

Issued:	1976		1975	
	Number of Shares	**Value of Shares**	Number of Shares	Value of Shares
		(Thousands)		(Thousands)
5% preferred shares (i)	**40,000**	**$ 4,000**	40,000	$ 4,000
Preferred shares 4¼% series (ii)	**15,000**	**1,500**	15,000	1,500
Preferred shares 6% series (iii)	**50,000**	**5,000**	50,000	5,000
10¼% second preferred Series A (iv)	**1,152,000**	**28,800**	1,200,000	30,000
9.24% second preferred Series B (v)	**1,600,000**	**40,000**		
$1.25 convertible preferred shares (vi)				
Balance at beginning of year	**261,284**	**5,226**	1,772,659	35,453
Converted at varying dates into common shares without nominal or par value	**(217,394)**	**(4,348)**	(1,511,375)	(30,227)
	43,890	**878**	261,284	5,226
Issued and outstanding		**80,178**		45,726
Deduct preferred shares to be redeemed within one year (iv)		**1,200**		1,200
Balance at end of year		**$78,978**		$44,526

During the year the company issued for cash $40,000,000 cumulative redeemable second preferred shares Series B. The net proceeds received were $38,700,000 after deducting underwriting commission and expenses of issue.

(i) Redeemable at the option of the company on thirty days notice at $104 per share.

(ii) Redeemable at the option of the company on thirty days notice at $102.50 per share.

(iii) Redeemable at the option of the company on thirty days notice at $104 per share on or before February 1, 1977, thereafter reducing at various dates to a minimum redemption price of $101 per share.

(iv) Commencing June 1, 1976 the company, through the operation of a cumulative mandatory sinking fund, is required to redeem 48,000 shares per annum at a price of $25 per share plus an amount equal to all dividends accrued and unpaid. Through the operation of a non-cumulative optional sinking fund an additional 36,000 shares may be called for redemption on the same terms. Redemptions for other than sinking fund purposes may be made subsequent to January 31, 1980 and prior to January 31, 1981 at $26.25 per share plus an amount equal to all dividends accrued and unpaid and, thereafter, at various dates and at various amounts reducing to a minimum redemption price of $25 per share.

(v) Commencing with the calendar quarter ending March 31, 1977, the company is required to make all reasonable efforts to purchase for cancellation in the open market 12,000 shares in each calendar quarter at a price not exceeding $25 per share plus costs of purchase and such obligation shall carry over to the succeeding calendar quarters in the same calendar year. If after all reasonable efforts the company is unable so to purchase an aggregate of 48,000 shares in the four quarters of any calendar year, the company's obligation to purchase shares with respect to such calendar year shall be extinguished. The company may redeem the shares subsequent to December 21, 1981 and prior to December 21, 1982 at $26.25 per share plus an amount equal to all dividends accrued and unpaid and, thereafter, at various dates and at various amounts reducing to a minimum redemption price of $25 per share.

(vi) Redeemable at the option of the company on thirty days notice at $20 per share, otherwise convertible into two common shares. The company has exercised its option and will redeem shares outstanding on January 28, 1977 at $20 per share.

14. Common shares

Authorized:

30,000,000 without nominal or par value

Issued:

	1976		1975	
	Number of Shares	**Value of Shares**	Number of Shares	Value of Shares
		(Thousands)		(Thousands)
Balance at beginning of year	**14,198,376**	**$105,833**	10,075,466	$ 65,429
Issued on conversion of $1.25 preferred shares	**434,788**	**4,348**	3,022,750	30,228
Issued on exercise of share purchase warrants	**340**	**3**	160	1
Issued during the year	**2,000,000**	**24,500**	1,100,000	10,175
Balance at end of year	**16,633,504**	**$134,684**	14,198,376	$105,833

At December 31, 1976 the company has reserved 682,440 common shares for issue as follows:

In connection with share purchase warrants outstanding exercisable at a price of $9 per share (price is subject to adjustment in certain circumstances). The warrants expire May 15, 1978	594,660
In connection with the $1.25 cumulative redeemable convertible preferred shares	87,780
	682,440

On November 16, 1976 the company sold 2,000,000 common shares without nominal or par value at a price of $12.25 per share, amounting to $24,500,000 in aggregate. The net proceeds received were $22,970,000 after deducting underwriting commission of $1,350,000 and expenses of issue of $180,000.

15. Remuneration of directors and officers

During the year ended December 31, 1976 the company paid aggregate remuneration of $74,000 to 13 directors as directors ($62,000 to 13 directors in 1975) and $554,000 to seven officers as officers ($382,000 to eight officers in 1975). Two officers were also directors in 1976 and two in 1975.

16. **Commitments**

The cost of the company's construction and expansion program for 1977 will amount to approximately $121,165,000. Commitments under contract pertaining to this program are approximately $63,838,000 at December 31, 1976 of which approximately $23,089,000 will be incurred in 1977.

The company has in effect a pension plan covering substantially all its employees. The aggregate unfunded past service liability amounted to approximately $14,796,000 at December 31, 1976. Of this amount $9,034,000 must be funded by December 31, 1981, and the balance over a period not exceeding 16 years.

17. **Interim rates**

The Public Utilities Board of Alberta has approved interim rate increases under which gas revenues of approximately $12,306,000 have been recorded as of December 31, 1976. In the event that the interim rate increase approved to date is not fully confirmed, the company will be required to refund the amount of such reduction to its customers.

The Public Utilities Board approved a rate increase to a subsidiary, Northwestern Utilities Limited, of $2,800,000. A portion of this increase has been contested and the issue between the intervenor and the Public Utilities Board is presently before the courts.

18. **Anti-Inflation Act**

Effective October 14, 1975 the government of Canada enacted the Anti-Inflation Act and subsequently issued Regulations which are presently scheduled to be in force until December 31, 1978. The legislation is applicable to increases in prices and profit margins, employee compensation and shareholder dividends. The government of the Province of Alberta has indicated that it expects the Public Utilities Board of Alberta will permit regulated companies that provide the province with essential utilities to earn rates of return sufficient to assure continued viability and economic strength of such companies.

19. **Comparative figures**

Certain of the 1975 comparative figures have been reclassified to conform with the financial statement presentation adopted for 1976.

Auditors' Report to the Shareholders

We have examined the consolidated balance sheet of Canadian Utilities Limited as of December 31, 1976 and the consolidated statements of earnings, retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the company as of December 31, 1976 and the results of its operations and the changes in financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Peat, Marwick, Mitchell & Co
Chartered Accountants

Edmonton, Canada
January 28, 1977

Ten-Year Growth Summary

(dollars in thousands except per share data)

	1976	1975	1974
Natural Gas Revenues	$ 217,732	$ 142,436	$ 91,486
Electric Revenues	78,133	57,945	46,295
	295,865	200,381	137,781
Operating Expenses			
Natural gas supply	134,679	70,852	40,179
Operating and maintenance	72,797	56,541	43,572
Taxes — other than income	17,013	11,804	8,035
Depreciation	15,648	13,293	12,906
	240,137	152,490	104,692
Operating Income	55,728	47,891	33,089
Other Income			
Interest capitalized during construction	1,304	4,022	1,601
Interest and dividends	764	417	223
Gain on purchase of long-term debt	532	405	286
Miscellaneous	935	527	464
	3,535	5,371	2,574
	59,263	53,262	35,663
Income Deductions			
Interest on long-term debt	19,617	15,446	13,902
Interest on loans to parent and affiliated companies	263	263	262
Other interest	1,978	3,852	2,691
Debt discount and expense amortized	387	290	272
	22,245	19,851	17,127
	37,018	33,411	18,536
Income Taxes	8,667	8,686	2,416
	28,351	24,725	16,120
Minority Interests	860	860	860
Net Earnings before Extraordinary Items	27,491	23,865	15,260
Extraordinary Items — Non-Recurring Gain (Loss)		2,329	444
Net Earnings	27,491	26,194	15,704
Preferred Dividends	3,631	5,075	2,781
Net Income to Common Shareholders	23,860	21,119	12,923
Common Shares Outstanding	16,633,504	14,198,376	10,075,466
Earnings — Dollars Per Common Share (reflecting 4-for-1 share split September 15, 1972)			
Basic			
Net earnings before extraordinary items	1.62	1.69	1.24
Net earnings	1.62	1.90	1.28
Fully Diluted			
Net earnings before extraordinary items	1.55	1.45	1.05
Net earnings	1.55	1.61	1.08
Common Dividends Paid (Not applicable prior to 1972)			
Amount	11,014	7,142	5,943
Dividends per share	.765	.65	.59
Electric Statistics			
Gross plant in service at cost	352,680	309,345	260,743
Accumulated depreciation	53,191	45,677	41,246
Capital additions	45,913	51,142	44,849
Sales (thousands of kilowatt hours)	2,181,637	2,024,713	1,920,408
Maximum demand (thousands of kilowatts)	455	445	388
Plant capacity (thousands of kilowatts)	686	686	523
Customers at year-end	99,629	94,040	88,822
Communities served	368	365	364
Miles of power lines	12,498	12,004	11,710
Gas Statistics			
Gross plant in service at cost	335,936	301,813	276,506
Accumulated depreciation	93,163	89,365	83,945
Capital additions	40,441	29,527	26,623
Sales (millions of cubic feet)	250,480	250,477	238,197
Maximum daily demand (millions of cubic feet)	1,430	1,318	1,228
Customers at year-end	400,474	373,254	353,331
Communities served	257	253	253
Miles of pipelines	13,576	12,122	10,363

1973	1972	1971	1970	1969	1968	1967	1966
$ 82,066	$ 78,875	$ 70,342	$ 62,972	$ 59,221	$ 53,809	$ 51,925	$ 50,594
38.305	33,849	30.552	27,666	21,968	18,830	16,725	15,068
120,371	112,724	100,894	90,638	81,189	72,639	68,650	65,662
35,907	32,357	26,982	22,695	21,330	19,766	19,381	18,086
34,729	33,389	29,103	26,365	23,812	20,606	18,615	17,163
6,829	6,516	5,959	5,288	4,755	4,366	4,076	3,902
11,019	10,134	9,716	9,378	7,921	7,134	6,845	6,361
88,484	82,396	71,760	63,726	57,818	51,872	48,917	45,512
31,887	30,328	29,434	26,912	23,371	29,767	19,733	20,150
785	2,170	774	194	1,091	939	383	156
208	466	704	480	336	584	665	294
328	36	379	179	66	197	52	72
253	306	243	16	202	115	67	88
1,574	2,978	2.100	869	1,695	1,835	1,167	610
33,461	33,306	31,234	27,781	25,066	22,602	20,900	20,760
11,931	11,033	8,804	6,870	6,116	5,785	4,825	4,037
371	459	263	372	375	47		
1,153	438	708	1,698	993	581	305	199
235	229	206	168	154	147	122	104
13,690	12,159	9,981	9,108	7,638	6,560	5,252	4,340
19,771	21,147	21,253	18,673	17,428	16,042	15,648	16,420
4,536	5,054	7,132	6,912	5,705	5,152	5,954	6,860
15,235	16,093	14,121	11,761	11,723	10,890	9,694	9,560
860	962	1,226	1,160	1,167	1,149	1,138	1,156
14,375	15,131	12,895	10,601	10,556	9,741	8,556	8,404
	(89)	183	234	2,888	207	14	256
14,375	15,042	13,078	10,835	13,444	9,948	8,570	8,660
2,787	2,766	2,514	2,514	2,514	2,514	2,415	2,214
11.588	12,276	10,564	8,321	10,930	7,434	6,155	6,446
10,064,906	10,062,646	10,056,024	8,948,528	8,873,752	8,873,672	8,860,860	8,838,608
1.15	1.23	1.03	.90	.91	.81	.69	.70
1.15	1.22	1.05	.93	1.23	.84	.69	.73
.99	1.05	.91	.80	.81	.74	.67	.68
.99	1.04	.93	.82	1.03	.76	.67	.70
5,535	5,231						
.55	.52						
218,202	198,165	175,477	147,521	132,294	118,556	94,189	77,813
35,954	31,814	28,337	24,568	21,084	18,901	17,093	15,478
21,341	24,514	29,123	16,447	15,513	26,089	17,735	10,912
1,782,908	1,520,031	1,274,649	1,118,239	967,276	769,501	645,283	563,112
376	342	295	281	245	216	178	149
512	370	367	367	344	197	197	193
84,598	80,492	77,246	74,193	72,042	70,076	67,503	65,487
365	365	359	355	343	342	342	340
11,245	10,823	9,951	9,715	9,197	8,497	7,602	7,205
251,705	236,920	221,191	211,269	200,069	189,287	180,667	171,964
78,593	73,760	68,854	64,038	59,289	55,032	51,050	47,152
17,080	16,543	10,594	11,830	11,477	9,457	9,299	8,892
236,598	228,630	203,497	183,526	169,964	150,761	148,667	141,560
1,109	1,132	1,115	969	894	918	784	752
335,494	317,766	303,253	289,457	278,412	266,669	255,332	247,157
253	251	249	240	238	229	221	206
9,837	9,439	9,166	8,753	8,106	7,328	6,410	5,689

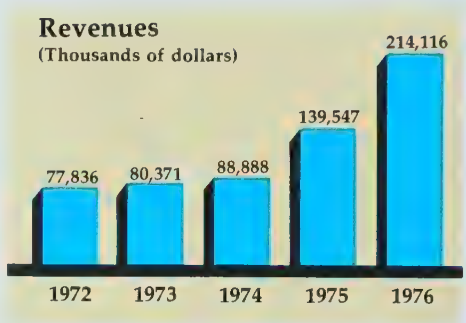
Natural Gas Operations

Service vehicles move out in early morning from Canadian Western's customer service centre close to downtown Calgary.

Canadian Utilities' natural gas operations are carried out by two main subsidiaries: Canadian Western Natural Gas Company Limited of Calgary, providing service to the southern half of Alberta, and Northwestern Utilities Limited of Edmonton serving the north-central region of the province. Altogether the companies supply more than 80 per cent of the natural gas consumed in the province.

A Northwestern subsidiary, Northland Utilities (B.C.) Limited, serves Dawson Creek and district in northeastern British Columbia.

Combined, the companies at year-end had a total of 400,474 customers in 257 communities and in rural areas. A record 27,220 new customers were added during the year, 37 per cent more than were connected in 1975, also a record year. Northwestern welcomed its 200,000th customer during the year; Canadian Western added three communities to its service territory.



	Residential	Commercial	Industrial	Other	Total
'76	68,824 32%	52,132 24%	89,816 42%	3,344 2%	214,116 100%
'75	52,358 38%	37,027 27%	47,849 34%	2,313 1%	139,547 100%
'74	36,503 41%	24,245 27%	27,043 31%	1,097 1%	88,888 100%
'73	34,034 42%	22,511 28%	22,888 29%	938 1%	80,371 100%
'72	34,123 44%	22,656 29%	20,278 26%	779 1%	77,836 100%

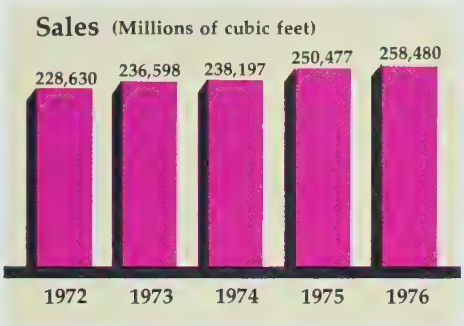
In the chart above natural gas revenues include only those resulting directly from the sale of natural gas. Natural gas revenues per financial statement include other miscellaneous operating revenues.

Rates

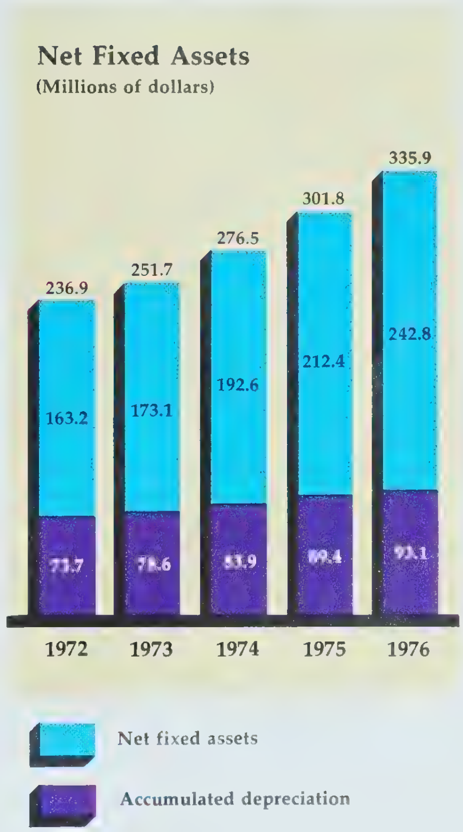
Natural gas revenues in 1976 were $217.7 million compared to $142.4 million the previous year. The increase is attributable mainly to higher rates allowed by the Alberta Public Utilities Board to cover increased gas supply costs.

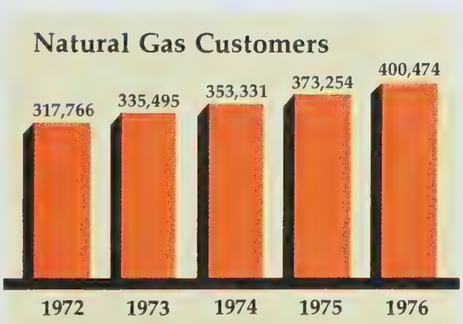
During the year Canadian Western submitted applications to the Public Utilities Board of Alberta for increased rates to be effective July 1, 1976 and January 1, 1977; Northwestern applied for higher rates to take effect May 1, 1976 and January 1, 1977. In the cases of both companies the 1976 rate adjustments were required primarily to recover the increased cost of gas supply resulting from a change in the support price of natural gas under The Alberta Natural Gas Rebates Act. The January 1, 1977 increases were necessary to meet continued inflationary pressures on the costs of wages, materials and supplies, higher costs of peak load gas purchases and higher costs of financing capital expenditures. The applications all received interim approval.

In September, the Public Utilities Board gave final approval to Canadian Western's 1975 rates. In its decision the Board determined that the company had exceeded its revenue requirements by $151,000 and this amount was refunded to customers in 1976 along with an additional $342,000 resulting from a change in the accounting treatment of the sale of a Calgary office building in 1975. The latter item did not affect the company's net earnings.



	Resi-dential	Com-mercial	Industrial	Other	Total
'76	64,289 25%	63,273 24%	125,258 49%	5,660 2%	258,480 100%
'75	67,317 27%	67,049 27%	109,985 44%	6,126 2%	250,477 100%
'74	62,268 26%	63,025 26%	106,689 45%	6,215 3%	238,197 100%
'73	60,383 26%	60,299 25%	109,975 46%	5,941 3%	236,598 100%
'72	62,316 27%	61,093 27%	100,179 44%	5,042 2%	228,630 100%





	Resi-dential	Com-mercial	Industrial & Other	Total
'76	361,393 90.2%	38,432 9.6%	649 0.2%	400,474 100%
'75	336,064 90.0%	36,648 9.8%	542 0.2%	373,254 100%
'74	317,535 89.9%	35,286 10.0%	510 0.1%	353,331 100%
'73	301,084 89.7%	33,874 10.1%	537 0.2%	335,495 100%
'72	284,764 89.6%	32,513 10.2%	489 0.2%	317,766 100%

In another decision handed down in January, 1977 on Canadian Western's 1976 rate application, the Public Utilities Board established the company's revenue requirements at $92,883,000, compared to $93,808,000 requested in the application. The difference of $925,000, which arose from the Board's re-determination of the company's income tax estimate and method of determining return on debt and equity capital, will be refunded to customers in 1977. The Board approved a return on common equity of 14.67 per cent as requested by the company.

A final decision on Northwestern's 1976 revenues is expected early in 1977.

The Alberta consumer has been shielded since 1974 from the full impact of rapid natural gas price increases by a provincial government rebate plan under which the province pays the difference between the field price of natural gas and a "support price" set by the government. The plan was originally proposed for a three-year period ending March 31, 1977. In 1976 the government announced its intention to extend the plan for an additional three years.

As of December 31, 1976 the field price of natural gas was 87.5 cents a thousand cubic feet, while the support price was 56 cents a thousand cubic feet. In 1976 the Alberta government, under the rebate program, shielded Alberta consumers from $70 million in natural gas costs. Of this total, $59 million flowed through to Canadian Western and Northwestern customers.

Sales

In 1976 natural gas sales volume was 258 billion cubic feet, three per cent over the previous year. Industrial consumption was up 14 per cent (15 billion cubic feet) over the year earlier; residential and commercial consumption declined because of higher than normal temperatures and possibly some response by consumers to appeals for conservation.

	Billions of Cubic Feet	Per Cent of Total
Industrial	125	49
Residential	64	25
Commercial	63	24
Other	6	2
Total	**258**	**100**

Gas Supply

The company's major expense item, gas supply, totalled $134.7 million in 1976, compared to $70.9 million in 1975. (These figures do not include gas supply costs shielded by the provincial government's Natural Gas Rebates Plan.)

The company pursues a program of acquisition and development of new gas properties. Shown below is a drilling site east of Edmonton.

The gas utilities obtain the bulk of their gas supplies from: oil fields where solution gas, extracted in conjunction with oil production, is gathered and processed; gas fields from which wet gas is gathered and centrally processed before delivery to pipelines; and dry gas fields from which gas can be introduced almost directly into pipelines. Company-owned gas producing properties are a significant source of supply for peak requirements. Also, volumes of gas are purchased from export companies and other natural gas pipeline companies.

Company geologists estimated that at December 31, 1976 the utilities owned 721 billion cubic feet of gas, and had under firm contract 2,817 billion cubic feet of gas reserves at 1000 BTU's a cubic foot from fields from which it produces or purchases natural gas; and that an additional 2,627 billion cubic feet will be available for purchase in the future from fields where the estimated gas producing life exceeds the term of the existing gas purchase contracts.

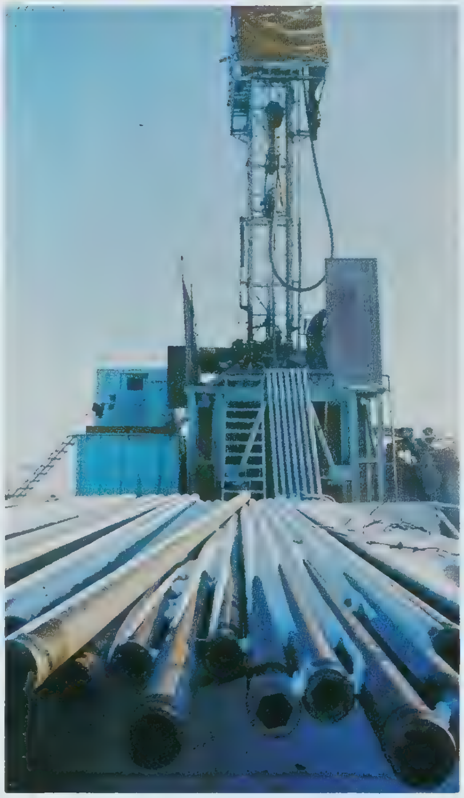
To meet future requirements, the companies pursue a program of acquisition and development of additional gas properties and gas supplies, and continue their policy of contracting for the most economical supplies of gas from other companies. Notwithstanding the Alberta government's policy that local consumers take precedence over out-of-province demand for natural gas, Canadian Utilities believes it is advisable to have further supplies at hand. For this reason the company has entered into agreements which enable the utilities to call upon the major gas exporters for very large quantities of base-load and peak-load gas.

Gas supply prices are determined to a large extent by agreement between the federal and Alberta provincial governments. It is an objective of both governments to permit the price of natural gas to rise in stages to "commodity value"; that is, a value equivalent to that of oil in terms of energy content. This policy is intended to increase the return to producers, and provide incentive for additional exploration and development. It is perhaps indicative of the effectiveness of this policy that 1976 was a record year in Alberta for gas exploration in terms of wells drilled and money invested.

During 1976, 106 contracts were negotiated for 516 billion cubic feet of new gas reserves, the majority of which are in the Willingdon-Myrnam and Medicine Hat areas. The price paid producers at December 31, 1976 was 87.5 cents per thousand cubic feet, plus "border flow back" of 22.5 cents.

Northwestern produced 14 per cent of its requirements from company-owned reserves in the Viking-Kinsella, Beaverhill Lake, Fort Saskatchewan, Fairydell-Bon Accord and other dry gas fields. Canadian Western's dry gas storage reservoirs at Carbon and Bow Island supplied 31 per cent of its total system demand. During 1976 the companies drilled 12 new wells of which nine proved successful.

Under the terms of federal and provincial legislation, all Alberta gas producers receive a pro rata share of net revenues generated by gas exported to the United States. Since Canadian Western and Northwestern are both gas producers, they participate in this border flow back. The funds are distributed by the Alberta Petroleum Marketing Commission which administers the program. The Public Utilities Board has agreed with the companies that



these funds may be used to finance exploration for new gas reserves. In 1976 the Board permitted the cost of successful wells to be included in the regulatory rate base; unsuccessful wells are to be expensed against border flow back funds.

New Construction

Capital expenditures by the gas utilities in 1976 were $40.4 million compared to $29.5 million in 1975, with inflation and market growth being the most important factors in the increase.

Major transmission system projects during the year included the construction of the 72-mile 10 and 12-inch Paddle River loop line; 27 miles of 8 and 6-inch Myrnam line; 34.2 miles of 16-inch transmission line connecting to the new Cominco fertilizer plant in southern Alberta;

Plastic pipe, transported on giant spools, is utilized for natural gas distribution systems in rural areas. Canadian Western Natural Gas pioneered the technique of plowing plastic pipe.

The company's gas utilities at the end of 1976 served over 400,000 customers. A record 27,220 new gas customers were added during the year.

and eight miles of 10-inch line connecting to the Alberta Gas Ethylene petrochemical plant near Red Deer. These and a number of smaller-scale transmission projects amounted to $12.7 million.

The distribution system required $24.1 million, primarily to expand the existing facilities to serve the large number of new customers. The remaining $3.6 million was spent for additions to service facilities and equipment.

Market Growth

Building permits with a total value of $1.292 billion, up 42 per cent over the previous year, were issued in 1976 in Calgary, Edmonton, Lethbridge, Red Deer, Fort McMurray and Grande Prairie, principal communities in the gas companies' service areas.

In Calgary $448 million worth of construction was initiated, mainly for new residential and commercial development. The comparable figure in 1975 was $393 million.

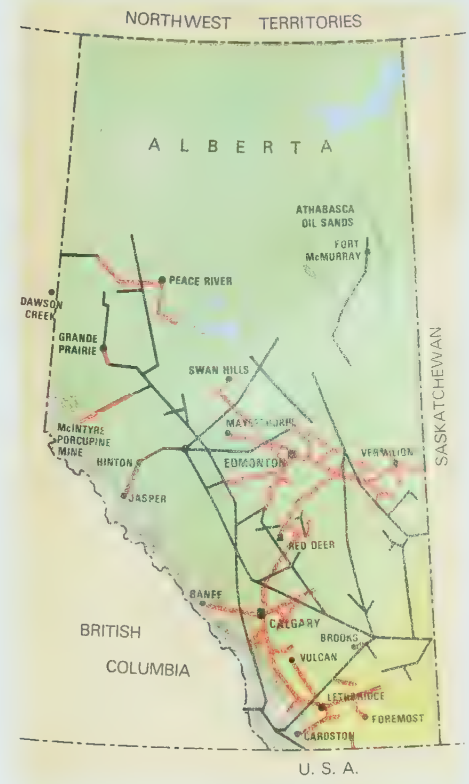
Metropolitan Edmonton launched $618 million worth of projects, up from $396 million the previous year. The 1976 total does not include $30 million for construction underway on Commonwealth Games facilities, $86 million for a recently announced health-sciences centre at the University Hospital or continuing work on the city's $64 million rapid transit system.

In Fort McMurray, fastest growing community in Northwestern Utilities' service area, construction activity more than doubled from the previous year to $89.7 million.

Lethbridge and Red Deer issued permits valued at $60.8 million and $59.8 million respectively. The Red Deer total was up 125 per cent over the year earlier. Grande Prairie's building permits totalled $16.1 million compared to $12.4 million in 1975.

The gas companies continue to take part in the Alberta government's rural gas program. A record total of 2,689 new services were installed in 1976, 220 more than in 1975.

Additional statistics on natural gas operations are shown in the Ten-Year Growth Summary on pages 22 and 23.



NATURAL GAS SYSTEM

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

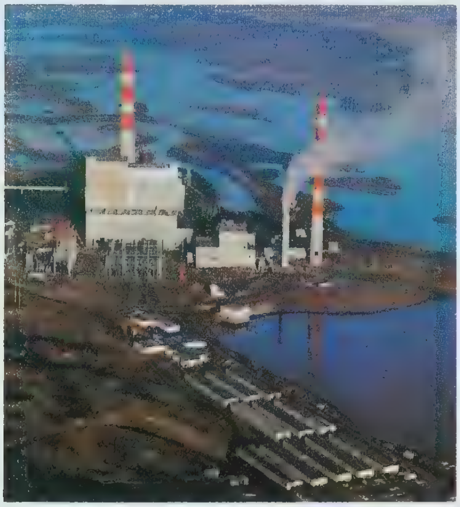
NORTHWESTERN UTILITIES LIMITED

MAJOR COMPANY PIPELINES

MAJOR PIPELINES OWNED BY OTHERS

The company's largest generating station stands south of the Battle River near Forestburg. Capacity of the plant is currently 366 megawatts.

Electric Operations



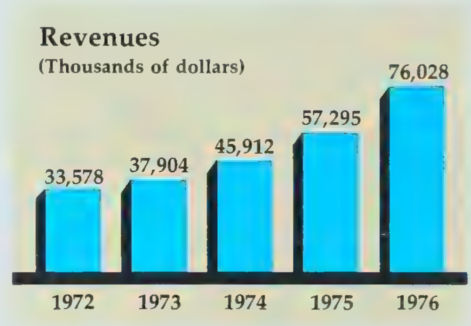
Canadian Utilities' electric operations are conducted by Alberta Power Limited, which serves 346 communities in east-central and northern Alberta, four communities in the Northwest Territories, including the town of Hay River, and 18 communities in the Yukon through a subsidiary, The Yukon Electrical Company Limited.

The continuing strength of the Alberta economy provided impetus to the company's growth throughout 1976. A record 5,589 new customers were added, raising the number at year-end to 99,629. Included in the total were 20,914 farm customers of whom 19,957 were members of 169 rural electrification associations.

During the year energy sales rose 7.75 per cent to 2,182 million kilowatt hours, while peak load grew to 455 megawatts, an increase of 10 megawatts over the previous year.

Electric revenues increased to $78.1 million from $57.9 million the previous year. Contributing substantially to the rise were rate increases which became effective in late 1975 and early 1976. These rate adjustments, approved by the regulatory boards in Alberta, the Yukon and the Northwest Territories, were essential to meet higher costs, particularly of fuel and purchased power.

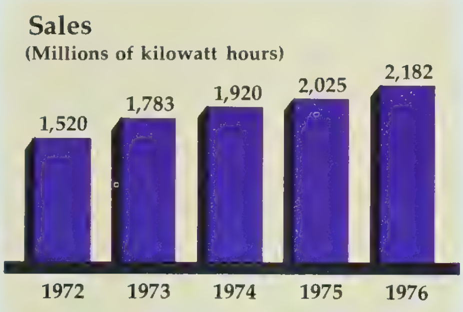
In Alberta an eight per cent rate increase went into effect on January 1, 1976 and a further 5.7 per cent received interim approval from the Public Utilities Board, effective May 1. A Public Utilities Board decision issued in November concerning Alberta Power's rates, determined that the company would exceed its revenue requirements for 1976 and directed the company to refund $500,000 to its customers. The refund was made from 1976 revenues.



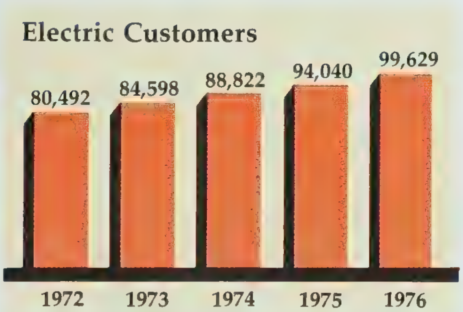
	Residential	Commercial	Industrial	REA & Other	Total
'76	16,677 22%	22,448 30%	27,514 36%	9,389 12%	76,028 100%
'75	12,309 21%	16,971 30%	21,062 37%	6,953 12%	57,295 100%
'74	9,632 21%	13,586 30%	16,759 36%	5,935 13%	45,912 100%
'73	8,203 22%	12,841 34%	13,459 35%	3,401 9%	37,904 100%
'72	7,612 23%	11,698 35%	11,076 33%	3,192 9%	33,578 100%

In the chart above electric revenues include only those resulting directly from the sale of electric energy. Electric revenues per financial statements include other miscellaneous operating revenues.

In the Yukon the company was compelled to seek three rate adjustments in response to increases in the cost of power purchased from the Northern Canada Power Commission (the federal government's electric utility), and rising prices of diesel fuel. A 21 per cent interim rate increase in the Northwest Territories went into effect on January 20, 1977.



	Resi-dential	Com-mercial	Industrial	REA & Other	Total
'76	402 18%	400 18%	1,100 51%	280 13%	2,182 100%
'75	368 18%	369 18%	1,029 51%	259 13%	2,025 100%
'74	323 17%	332 17%	1,005 52%	260 14%	1,920 100%
'73	290 16%	320 18%	978 55%	195 11%	1,783 100%
'72	268 18%	290 19%	779 51%	183 12%	1,520 100%



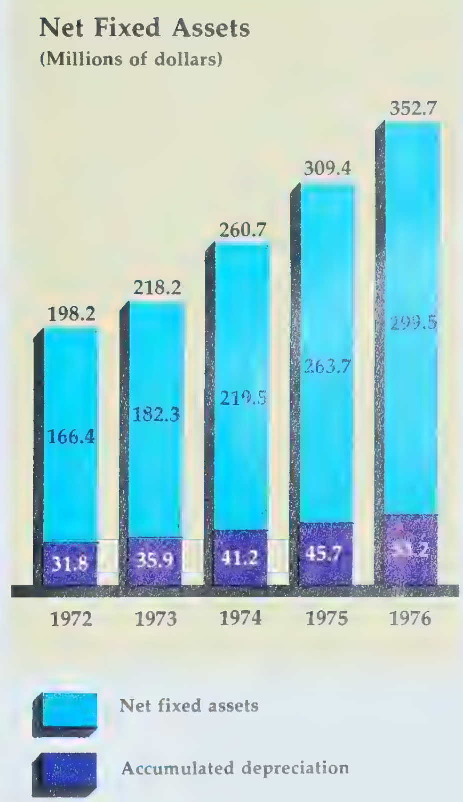
	Resi-dential	Com-mercial	Industrial	REA & Other	Total
'76	61,008 61%	14,120 14%	3,262 3%	21,239 22%	99,629 100%
'75	56,673 60%	13,574 15%	3,057 3%	20,736 22%	94,040 100%
'74	52,406 59%	13,354 15%	2,895 3%	20,167 23%	88,822 100%
'73	49,370 58%	13,273 16%	2,536 3%	19,419 23%	84,598 100%
'72	46,391 57%	12,804 16%	2,173 3%	19,124 24%	80,492 100%

An Alberta Power 8400-kilowatt gas-fired generating station stands in a majestic mountain setting in Jasper National Park.

In last year's annual report reference was made to Alberta Power's plan to sell its properties north of the 60th Parallel to the Northern Canada Power Commission. Negotiations for the sale were discontinued when the company's offer expired in July, 1976. The company will continue to supply electric power to the northern communities for the foreseeable future.

The most notable project contributing to the Alberta Power system's growth is Syncrude's oil sands plant near Fort McMurray, the fastest growing community in the company's service area. The $2 billion Syncrude project is proceeding on schedule with start-up scheduled for mid-1978. The work force at the site rose to 7,200 employees during the summer of 1976. More than 500 Alberta firms are supplying Syncrude with goods and services.

In other oil sands developments, the Alberta Oil Sands Technology and Research Authority has indicated that it will be participating with five oil companies in separate pilot projects to test various in situ methods of extracting oil. Investment in just the first phases of this program is estimated at $130 million. All five projects could lead to important economic development in areas served by Alberta Power.

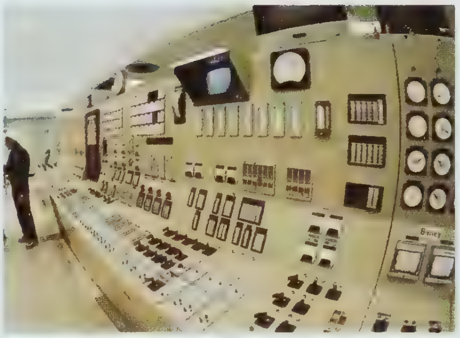


The production of conventional crude oil in Alberta was down 10 per cent in 1976, primarily because of reduced exports to the United States. Continuing declines in exports to the U.S., however, are expected to be offset by increased shipments to eastern Canada. Oilwell and pipeline pumping is an important segment of Alberta Power's market.

Other noteworthy projects in Alberta Power's service area, which were connected to the company system in 1976, include: an expansion of Procter and Gamble's pulp mill at Grande Prairie; a rapeseed processing plant at Sexsmith; and an alfalfa pelletizing plant at Mallaig. A gas processing plant at Zama Lake was completed during the year and will commence production in 1977.

The Mitsue-Mildred Lake-Fort McMurray transmission line ties in to the provincial power grid at this substation at Mitsue. The Mildred Lake-Fort McMurray section of the line will be energized at 240 kilovolts in mid-1977.

Alberta Power has embarked on the installation of a 375-megawatt addition to the Battle River generating station. Below is the main control panel at Battle River as seen through the camera's fish-eye lens.



Total value of building permits issued in the eight largest centres served by Alberta Power rose 83 per cent in 1976 to $147 million. The communities of Fort McMurray, Grande Prairie and Lloydminster experienced the greatest amount of building activity in the company's service area.

Five community franchises, including one with the City of Lloydminster, were renewed during the past year. The duration of most franchise agreements is 10 years.

The following table shows electric sales to the various customer categories:

	Thousands of Kilowatt Hours	Per Cent of Total
Industrial	1,100,076	51
Commercial	399,393	18
Residential	402,057	18
REA and others	280,111	13
Total	**2,181,637**	**100**

New Construction

Alberta Power's capital expenditures for additions to property, plant and equipment during the year were $45.9 million. The largest outlay was $8.8 million for the Mitsue-Mildred Lake-Fort McMurray transmission line, which was energized in June at 144 kilovolts. The Mildred Lake - Fort McMurray section of the line will be raised to 240 kilovolts in mid-1977. Another $7.6 million was required, largely for pollution control modifications, at the Battle River generating station. An additional $5.9 million was applied towards the purchase of a $25 million dragline for mining coal at the Battle River field. The company has negotiated a long-term agreement with Manalta Coal Ltd. to operate the dragline and mine coal from Alberta Power reserves. The balance of the coal required for the Battle River station will continue to be supplied by Forestburg Collieries Ltd., a subsidiary of Luscar Ltd.

The company has embarked on the installation of a 375-megawatt addition — Unit #5 — to the Battle River generating station. Total cost of the Unit #5 project is estimated at $236 million. Contracts have been placed for the purchase of the boiler and turbine generator and construction is expected to begin in June, 1977. Provincial load projections indicate a requirement for the additional generating capacity by the planned commissioning date of 1981.

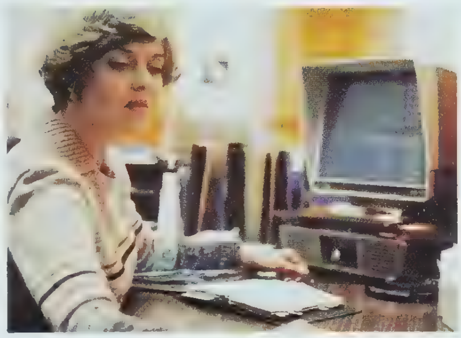
Other Operations

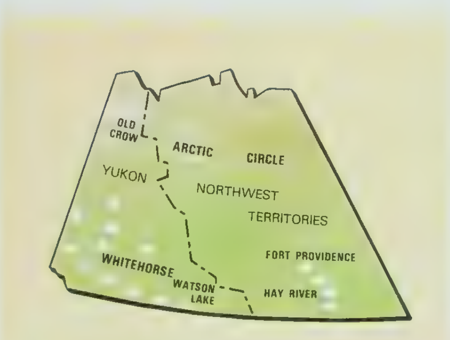
Alberta Power has filed an application for the development of a thermal-generating station at Sheerness, about 16 miles southeast of Hanna, Alberta and adjacent to a substantial coal deposit. The application calls for construction of two 375-megawatt units with commissioning of the first scheduled for the mid-1980's. Actual timing is dependent upon provincial load growth and other power developments in the province.

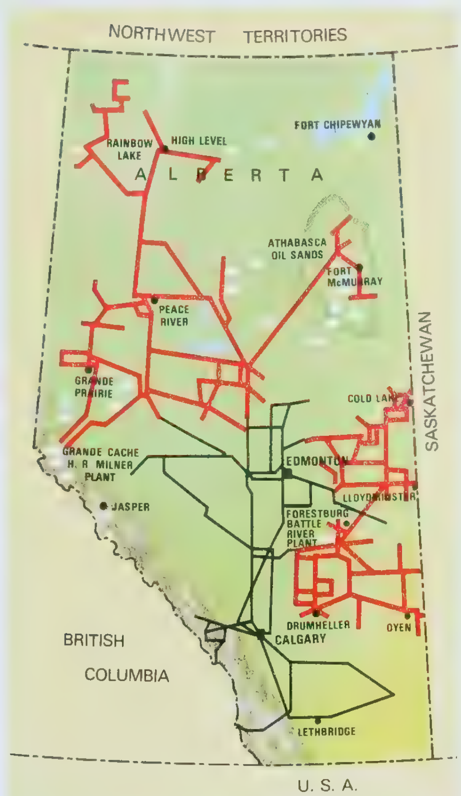
Planning for Sheerness has been under way since 1972, but the decision of the Alberta government not to approve Calgary Power's 2,250-megawatt Camrose-Ryley project has accelerated development plans for the Sheerness site.

Further data on electric operations are shown in the Ten-Year Growth Summary on pages 22 and 23.

Microfiche readers are a key element of a computerized system employed by the operating companies to streamline the recording and retrieving of customer billing information.







ELECTRIC SYSTEM

AREAS SERVICED BY ALBERTA POWER LIMITED

MAJOR COMPANY TRANSMISSION LINES

GENERATING PLANTS

TRANSMISSION LINES OWNED BY OTHERS

In 1975 the company established a new subsidiary, CU Engineering Limited, to market the organization's expertise in design engineering, project management and system and capacity evaluation for natural gas and electric distribution and transmission systems.

The new company has been awarded a contract to manage construction of a 170-mile gas pipeline from gas fields in northeastern Alberta to the Syncrude site near Fort McMurray. During 1976, CU Engineering also provided services in the areas of industrial energy studies, and electric power and rural natural gas distribution systems.

Another subsidiary, CU Ethane Limited, was formed in 1976 to carry out a joint venture with Dome Petroleum Limited to build and operate a 20,000 barrel-a-day ethane extraction plant in Edmonton. This project, which was outlined in the 1975 annual report to shareholders, will involve a $40 million expansion of an existing Dome facility. Natural gas feedstock for the plant will come from the main transmission lines flowing into south Edmonton.

All approvals for the project have been received and site preparation has begun. The plant is expected to be on stream by mid-1978.

Board of Directors

R. F. Calman
Executive Vice-President
IU International Corporation
Philadelphia, Pa.

* **G. L. Crawford, Q. C.**
Barrister & Solicitor
McLaws & Company
Calgary, Alberta.

W. D. H. Gardiner
Deputy Chairman and
Executive Vice-President
The Royal Bank of Canada
Toronto, Ontario.

E. W. King
President
Canadian Utilities Limited
Edmonton, Alberta.

P. L. P. Macdonnell, Q. C.
Barrister and Solicitor
Milner & Steer
Edmonton, Alberta.

J. E. Maybin
Chairman and Chief Executive Officer
Canadian Utilities Limited
Toronto, Ontario.

* **D. R. B. McArthur**
Chairman
Inland Cement Industries Ltd.
Edmonton, Alberta.

* **W. S. McGregor**
President
Numac Oil & Gas Ltd.
Edmonton, Alberta.

W. S. McLeese
President
Trans Canada Freezers Limited
Toronto, Ontario.

J. M. Seabrook
Chairman and President
IU International Corporation
Salem, New Jersey, U.S.A.

* Member of audit committee

Honorary Directors

** **F. C. Manning**
Calgary, Alberta.

D. K. Yorath
Edmonton, Alberta.

** Mr. Manning will not be eligible for re-appointment at the annual meeting on April 21, 1977 as he will have attained the company's mandatory retirement age for Honorary Directors.

Canadian Utilities Senior Officers

J. E. Maybin
Chairman and Chief Executive Officer

E. W. King
President

K. A. Biggs
Senior Vice-President Finance

Staff Executives

D. R. Brandt
Vice-President

A. M. Anderson
Treasurer

H. N. Bottomley
Controller

W. A. Sullivan
Secretary

Harry Brown
Assistant Secretary and
Assistant Treasurer

Edith M. Slipper
Assistant Secretary

Subsidiary Company Executives

ALBERTA POWER LIMITED

E. W. King
President and Chief Executive Officer

W. G. Sterling
Senior Vice-President

R. H. Choate
Vice-President

D. B. Mitchell
Vice-President, Industrial Relations

Keith Provost
Vice-President

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

NORTHWESTERN UTILITIES LIMITED

E. W. King
President and Chief Executive Officer

J. H. Pletcher
Senior Vice-President

D. B. Mitchell
Vice-President, Industrial Relations

D. L. Weiss
Vice-President, Gas Supply

A. J. L. Fisher
Vice-President and General Manager
Canadian Western Natural Gas
Company Limited

B. M. Dafoe
Vice-President and General Manager
Northwestern Utilities Limited

Other Subsidiaries Senior Operating Officers

CU ENGINEERING LIMITED

D. M. Murray
General Manager

CU ETHANE LIMITED

D. R. Brandt
President

CU RESOURCES LIMITED

D. L. Weiss
Manager

Subsidiary Companies

Alberta Power Limited
and subsidiaries:
The Yukon Electrical Company Limited
Yukon Hydro Company Limited

Canadian Western Natural Gas
Company Limited

Northwestern Utilities Limited
and subsidiary:
Northland Utilities (B.C.) Limited

CU Engineering Limited

CU Ethane Limited

CU Resources Limited

Registered Head Office

10040 - 104 Street
Edmonton, Alberta, Canada T5J 2V6
Telephone: (403) 424-6161

Toronto Office
2314 Commercial Union Tower
Toronto Dominion Centre
Toronto, Ontario, Canada M5K 1H1
Telephone: (416) 869-3868

Transfer Agent and Registrar

Common Shares and Preferred Shares:
Montreal Trust Company
Montreal/Toronto/Winnipeg/Regina
Calgary/Edmonton/Vancouver

Stock Exchange Listings

Common Shares:
Toronto, Montreal and Alberta
Stock Exchanges

Preferred Shares:
10¼% Second Preferred Series A
9.24% Second Preferred Series B
Toronto and Montreal Stock Exchanges

5% Preferred
4¼% Series Preferred
6% Series Preferred
Toronto Stock Exchange

Auditors

Peat, Marwick, Mitchell & Co.
2500 Alberta Telephone Tower
10020 - 100th Street
Edmonton, Alberta.

Valuation Day

The following are the Valuation Day prices for Canadian Utilities' common shares and warrants, adjusted for the stock split of September 15, 1972.

Common Shares	$9.31
Warrants	$2.13

Annual Meeting

The annual meeting of shareholders will be held in Edmonton on April 21, 1977.

LITHOGRAPHED IN CANADA

NESBITT THOMSON
AND COMPANY LIMITED

MEMBERS
THE TORONTO STOCK EXCHANGE
MONTREAL STOCK EXCHANGE
VANCOUVER STOCK EXCHANGE
ASSOCIATED WITH
NESBITT THOMSON NEW YORK CORPORATIO
MEMBER OF NEW YORK STOCK EXCHANGE

RESEARCH

AUGUST 2, 1976

Canadian Utilities Limited

CU - TSE, MSE

Current Price	1976 Price Range	E.P.S. (1) 1974	1975	1976E	P/E Ratio 1976E	Ind. Div.	Yield
$12.00	$12 1/2-$9 1/2	$1.05	$1.45	$1.60	7.5	$0.74	6.2%

(1) Fully-diluted operating earnings.
* Year-end December 31.

SUMMARY AND CONCLUSION

1975 Results

Fully-diluted operating earnings of Canadian Utilities Limited reached $1.45 per share in 1975, up 38% from $1.05 in 1974. The improvement reflected continued growth in operations and the effects of interim rate increases granted in 1975 for all three major subsidiaries. As a result of favourable regulatory treatment, the return earned on the average book value of the common equity rose fr an inadequate level of approximately 13.1% in 1974 to approximately 16.1% in 1975.

1976 Outlook

In 1976, earnings are expected to increase approximately in line with the growth in equity per share. On a fully-diluted basis and including non-utility income, earnings are estimated at $1.60 per share, up 10% from $1.45 in 1975.

Longer-Term Prospects

Over the next five years, demand for electricity in Alberta is forecast to increase at a compound rate of 10.0% annually and the demand for natural gas at a rate of 10.8% annually. To meet the anticipated demand within its service areas, CU will be engaged in major expansion programs whose costs are accelerated by inflation and, in the electric sector, by expenditures on anti-pollution measures. Consequently, rate base growth will be rapid and is forecast to average approximately 15% annually over the next five to six years for the electric and gas operations combined.

Assuming continuation of the present regulatory system in Alberta, CU should realize a return on the book value of its common equity of approximately 15% annually, including non-utility income and earnings contributions from new areas of operations such as its participation in ethane extraction. Earnings growth should tend to parellel the growth in common equity arising from retained earnings and equity financing. After allowing for a dividend payout ratio of 50% - 55% and with the Company in a position to effect new financing without dilution of shareholders' equity, the longer-term growth rate in earnings per share should be in the range of 7% - 8% annually. Dividends should rise in line with earnings with an increase in the annual rate of at least 8% expected later this year.

Recommendation

CU operates in a province where the economic outlook is excellent and where the regulatory climate assists the utilities in the financing of rapid rate base expansion. The common shares are recommended for sound investment quality and good prospects for growth in earnings and dividends.

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AUGUST 2, 1976
MONTREAL, QUEBEC

CONSOLIDATED FINANCIAL POSITION

During 1975, Canadian Utilities Limited ("CU") significantly strengthened its capital structure as is evident from the figures in the following table.

TABLE I

	Consolidated Capitalization			
	December 31, 1975		December 31, 1974	
	($'000)	(%)	($'000)	(%)
Short-Term Notes Payable and Due Bank	51,399	11.6	45,578	11.5
Long-Term Debt	184,568	41.8	194,535	49.4
	235,967	53.4	240,113	60.9
Minority Interest (1)	20,008	4.5	20,008	5.1
Preferred Shares - Non-Convertible				
5% Series	4,000		4,000	
4 1/4% Series	1,500		1,500	
6% Series	5,000		5,000	
10 1/4% Second Preferred Series "A"	28,800 (2)			
	39,300	8.9	10,500	2.7
$1.25 Convertible Preferred (4)	5,226	1.2	35,453	9.0
Common Equity (3)				
(1975: 14,198,376 shares)	141,400	32.0	87,871	22.3
(1974: 10,075,466 shares)				
	441,901	100.0	393,945	100.0

Notes:
(1) Represent subsidiary preferred shares not owned by CU.
(2) Excluding $1,200 to be redeemed within one year.
(3) The common equity as shown in CU's annual reports reflects the inclusion of "Undertakings, Franchise and Gas Rights" capitalized at $8.0 million, which is not recognized as part of the rate base.
(4) Considered to be part of the common equity.

The following are comments on the major improvements in CU's financial position achieved in 1975:

1. The reduction in the debt ratio to 53.4% from 60.9% of capitalization resulted from an issue of $30.0 million preferred shares and from other additions to total shareholders' equity in the amount of $23.3 million.

2. The increase in common shareholders' equity, including the $1.25 convertible preferred shares, to $146.6 million in 1975 from $123.3 million in 1974, an increase of $23.3 million or 19%, arose from the following sources:

	($ Millions)
Retained Operating Earnings	11.6
Common Equity Financing	9.5
Extraordinary Income	2.3
	23.4
Less: Preferred Dividends Declared in Advance	0.1
	23.3

At the end of 1975, IU International Corporation owned 10,916,670 shares, which represented 74.2% of the number of shares outstanding, assuming full conversion of the remaining $1.25 preferred shares. Other shareholders held 3,804,274 shares or 25.8%. The number and percentage of shares held publicly are expected to increase further due to additional common equity financing and the exercise of 595,000 warrants, exercisable at $9.00 per share on or before May, 1978.

THE COMPANY

Canadian Utilities Limited is a holding company and the parent of three wholly-owned subsidiaries operating major electric and gas utilities in the Province of Alberta. The electric utility is operated by Alberta Power Limited ("APL"), principally in Alberta and to a small extent in the Northwest Territories. Through its subsidiaries, The Yukon Electrical Company Limited and Yukon Hydro Company Limited, APL also serves the Yukon Territory. Canadian Western Natural Gas Company Limited ("CWNG") and Northwestern Utilities Limited ("NUL") produce, transmit and distribute natural gas to most of the major cities and towns, and many rural areas in Alberta. NUL also provides natural gas service to Dawson Creek, B.C., through its subsidiary, Northland Utilities (B.C.) Limited.

In 1975, CU Engineering Limited was incorporated to market the organization's expertise in design engineering and utilities project management.

In July, 1975, it was announced that the Company had entered into negotiations with the federal government's electric utility, the Northern Canada Power Commission for the sale of the Yukon Electrical and other properties north of the 60th parellel. However, negotiations have ceased following the expiry of CU's offer at the end of July, 1976.

Also in 1975, CU and Dome Petroleum Limited ("Dome") announced a joint venture to build and operate a 20,600 barrels per day ethane extraction plant at Edmonton. This project forms an integral part of the worldscale petrochemical industry being established in Alberta.

CU is the only investor-owned utility in Canada with major operations in both electric and gas services. It supplies approximately 14% of Alberta's electric energy requirements and 75% - 80% of the province's gas requirements. In 1975, the electric operations contributed 52% and the natural gas operations 48% to consolidated net income.

OPERATING ENVIRONMENT

The Alberta Economy

The Alberta economy was again strong in 1975 with a low unemployment rate of 2.7% versus the national average of 7.1%. The population growth was also rapid at 3.2% versus 1.5% for Canada as a whole. New capital investments in the private and public sectors rose over 16% to more than $5.2 billion and were particularly strong in the resource, construction and utility industries.

The prospects for continuing strength in the Alberta economy appear excellent. The petroleum industry is benefitting from further increases in oil and gas prices and more favourable investment conditions as reflected in increased drilling activities. Major resource and industrial developments include: The Syncrude and other Tar Sands projects; the efforts to test in situ recovery methods of heavy oil deposits at Cold Lake and several other sand formations in the province; plans for increased utilization of Alberta's large coal reserves, including coal gasification; and the build-up of petrochemical and related industries of worldscale proportions.

The capital value of proposed projects in Alberta reached $10.2 billion in January, 1976, up from $7.4 billion a year earlier.[1] The latest figure represents 45 major undertakings of which 18 projects with a capital value of $6.6 billion are in the petroleum and petrochemical sector. Developments of this magnitude will create strong demand for utility services of all kinds. The aggregate value of proposed projects in the utility industry was approximately $3.1 billion as of January, 1976, although it should be noted that this figure includes expansion plans into the mid-1980's.

The following table, prepared by The Forecast Committee of the Electric Utility Planning Council in Alberta, dated May 12, 1976, shows forecasted electric demand in the province over the next ten years.

TABLE II

Alberta Interconnected System
Forecast of Demand for Electricity 1975-1985

	Megawatt	% Increase
1975 (A)	2,599.4	7.3
1976	2,936.6	13.0
1977	3,149.4	7.2
1978	3,449.6	9.5
1979	3,800.1	10.2
1980	4,179.9	10.0
1981	4,532.2	8.4
1982	4,893.7	9.0
1983	5,282.2	7.9
1984	5,687.1	7.7
1985	6,114.3	7.5

(1) Source: "List of Industrial Projects in Alberta", a publication of the Business Service Branch of the Department of Business Development and Tourism.

The forecast compound growth rate in demand for electric energy is 8.9% annually over the next ten years with a faster growth of approximately 10.0% annually projected for the 1975 - 1980 period.

As an indication of the projected demand for natural gas in Alberta, the following figures were extracted from the report on Canadian Natural Gas Supply & Requirements published by the National Energy Board in April, 1975.

TABLE III

NEB Forecast of Demand for Natural Gas in Alberta 1975-1985 (BCF)

	Residential	Commercial	Petrochemical	Other Industrial	Thermal	Total
1975	76.9	73.4	55.7	68.3	53.7	328.0
1976	79.6	77.5	71.2	72.1	56.3	356.7
1977	82.1	81.3	134.1	76.1	60.1	433.7
1978	84.7	85.2	149.9	80.3	63.9	464.0
1979	87.1	88.7	149.9	99.7	67.5	492.9
1980	89.6	92.4	188.3	104.4	72.0	546.7
1981	90.9	96.6	190.2	109.3	74.5	561.5
1982	92.2	100.9	192.2	114.5	75.0	574.8
1983	93.5	105.4	194.3	120.0	76.0	589.2
1984	94.8	110.1	196.5	125.8	77.0	604.2
1985	96.1	114.9	214.0	131.9	77.9	634.8
Compound Annual Growth Rate						
10-Year: 1975 - 1985	2.2%	4.6%	14.4%	6.8%	3.8%	6.8%

While the projected compound annual growth rate averages 6.8% over the ten-year period 1975 - 1985, the growth forecast for the next five years to 1980 is significantly faster at 10.8% annually. It is evident that petrochemical developments in Alberta are expected to provide a strong impetus for the growth in demand. A significant portion of the demand in the petrochemical sector takes the form of feedstock requirements to be supplied by gas processing plants extracting ethane from the natural gas stream.

Regulation

CU's utility operations are regulated by the Public Utilities Board in Alberta. As is the case in other jurisdictions, allowable rates are determined on a cost-of-service basis which includes return on capital investment. The allowable rate of return levels are generally in line with those granted by other regulatory boards in Canada. However, two features of the regulatory system in Alberta make it particularly responsive to the needs of utilities which are expanding rapidly in a period of high inflation and high financial costs.

1. Interim rate increases are normally granted promptly for the full amounts applied for once the need for rate increases is clearly established. The interim increases are subject to later confirmation following public hearings.

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2. The use of a future test year whereby the interim increases are designed to cover cost of service including a fair return for the full year in accordance with the Company's forecast of rate base, operating expenses, and financial costs.

This regulatory procedure solves two important problems of the utilities: regulatory lag is virtually eliminated; and, dilution of shareholders' equity is prevented since the allowable rates take into account projected financing, including equity financing, while permitting increases in earnings per share on the new number of shares to be outstanding.

The time elapsed from the filing of applications to the granting of interim rate increases has been approximately one month as shown in the following table taken from CU's 1975 annual report. The table also shows the allowable levels of return on common equity for each of the major subsidiaries.

TABLE IV

Canadian Utilities - 1975 Rate Applications

	Alberta Power	Canadian Western	Northwestern Utilities
Date application filed	July 2	July 25	August 25
Interim rates approved effective:	August 1	September 1	October 1
Return on common equity	14.3%	15.0%	14.8%

The regulatory procedures employed in Alberta have been successful in creating investor confidence in the financial integrity of the province's utilities, as can be seen in the following two developments. The credit rankings for the debt securities of both Canadian Utilities and Calgary Power were upgraded in 1976 by C.B.R.S. Limited (Canadian Bond Rating Service); and, the market prices of the common shares of both Canadian Utilities and Calgary Power appear to have stabilized at premiums of 15% - 20% over book value per share, thus assisting these companies in meeting their equity financing requirements without diluting book values or earnings per share.

ELECTRICAL OPERATIONS

Alberta Power Limited, CU's arm in electrical operations, serves 347 communities in east-central and northern Alberta, as well as parts of the Northwest Territories. Through its subsidiary, The Yukon Electrical Company Limited, the company also supplies 18 communities in the Yukon. The eventual sale of the operations in the Yukon and Northwest Territories to the Northern Canada Power Commission is not expected to have a negative effect on earnings. APL's operations in northern Canada represent only approximately 1% of consolidated net income and this potential reduction is expected to be more than offset by the reinvestment of the proceeds to be received from the sale.

Electrical Operations: Growth Record 1970-1975

The following table shows selected statistics highlighting the growth in electric operations over the past five years.

TABLE V

APL - Growth Record 1970-1975

	Generating Capacity (MW)	Customers At Year-End	Electric Sales (Mil.KW)	Approx. Rate Base ($ Mil.)	Net Income (1) ($'000)
1970	367	74,193	1,118	109.0	4,027
1971	367	72,246	1,275	114.0	5,448
1972	512	80,492	1,520	118.0	6,824
1973	523	84,598	1,783	141.0	6,876
1974	686	88,822	1,920	165.0	7,032
1975	686	94,040	2,025	200.0	10,546
Compound Annual Growth Rate					
5-Year: 1970 - 1975	13.3%	4.8%	12.6%	12.9%	21.0%

Note: (1) Net income available common, excluding extraordinary items.

Generating capacity increased 31% in 1975 with the completion of a fourth unit at the Battle River plant, which went into service in December, 1975. The total cost of this 150 megawatt unit is approximately $66.0 million, including pollution control modifications to be completed in 1976. Approximately 77% of year-end 1975 generating capacity is coal fired.

Electric sales have increased in line with generating capacity and at a significantly faster rate than the growth in the number of customers, reflecting large new individual industrial loads.

Rate base growth in the electric operation has proceeded at an annual rate averaging nearly 13% since 1970, accompanied by a stronger growth of 21% annually in net income. The compound growth rate in net income over the five-year period was significantly enhanced by the 50% increase achieved in 1975, primarily as a result of the more adequate return on rate loans now being allowed.

Outlook for Electrical Operations

Generating Capacity

Projections used by The Forecast Committee of the Electric Utility Planning Council in Alberta forecast the growth in energy sales for APL over the next ten years as shown in table on the following page:

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TABLE VI

APL - Forecast of Energy Demand
1975 - 1985

Year	(Mil. KW)	Annual Increase (%)
1975 (A)	2,025	5.5
1976	2,356	16.3
1977	2,641	12.1
1978	2,794	5.8
1979	2,980	6.7
1980	3,197	7.3
1981	3,445	7.8
1982	3,659	6.2
1983	3,939	7.7
1984	4,158	5.6
1985	4,391	5.6

These projections indicate a growth rate averaging close to 10.0% annually for the five years 1975 - 1980 and approximately 6.5% annually from 1980-1985. The load projections suggest that there will be a need for substantial additional generating capacity for APL by 1981. To meet these requirements, the company is conducting preliminary engineering studies for a 375 megawatt Unit Number Five at Battle River. The addition of this unit would increase year-end 1975 generating capacity by approximately 55%.

Rate Base Expansion

APL's capital expenditures for 1976 are estimated at approximately $45 million, as compared with $51.3 million in 1975 when the fourth unit at Battle River was being completed. In 1977 and 1978, APL's annual expenditures should remain at a level of approximately $50 million, mainly for new transmission and distribution facilities.

Over the next three years, after 1978, as the construction of the fifth and larger unit at Battle River begins, the annual capital expenditures in the electric operation will likely reach the $100 million level. The cost of the additional facility at Battle River, which may be shared with other utilities, is estimated at over $200 million.

While the forecast growth rates in electric energy sales over the next five and ten years of approximately 10.0% and 6.5%, respectively, are below the 12.6% actual growth from 1970 - 1975, rate base expansion will be more rapid due to the strong inflationary trend in construction costs, including major outlays for anti-pollution measures. Based on the expected expenditures, the growth in APL's rate base should average 16% - 17% annually between 1975 - 1981.

Following Alberta's refusal to approve Calgary Power's proposal for a major thermal electric project based on coal reserves in the Camrose Ryley area, it is expected that CU will apply to the Alberta Energy Resources Conservation Board for permission to develop coal deposits at Sheerness, located within APL's service territory. It is believed that sufficient coal

reserves are available for the requirements of two generating plants with a capacity of 375 MW each and that the first plant will be scheduled to go into service in 1983. It is possible that new generating plants at Sheerness may be jointly owned by CU and Calgary Power. In the above forecasts, no consideration was given to this development or to the accelerated economic activity that would take place in this part of APL's franchise areas.

Electric Utility Income

For 1976, APL's net income after preferred dividends is estimated at approximately $11.9 million, up 13% from $10.5 million in 1975. Over the next five years, net income from electric operations should rise approximately in line with the expected average growth in rate base of 16% - 17% annually.

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NATURAL GAS OPERATIONS

CU's markets in Alberta cover most of the province. The principal areas served are in Edmonton, Calgary, Lethbridge, Grande Prairie, and Red Deer. These five cities have a combined population of approximately 1,000,000 with CU serving 255,000 customers. Also served are 249 smaller communities, as well as rural areas with a combined population of approximately 320,000 with CU serving an additional 108,000 customers. In 1975, the franchise agreement between the City of Edmonton and Northwestern Utilities Limited ("NUL") was renegotiated for a further 10-year term.

Canadian Western Natural Gas and NUL supply 75% - 80% of Alberta's total annual gas consumption. Their combined sales volume in 1975 was 255 BCF. In comparison with the other investor-owned gas distribution companies in Canada, CU's gas operations ranked second in terms of annual volume sold, approximately 20% below Consumers' Gas and 9% ahead of Union Gas. Due to the rapid growth expected in Alberta over the next several years, a period during which gas sales in eastern Canada are expected to level out due to lack of new supplies, CU could achieve the largest sales volume among the domestic investor-owned gas utilities.

Gas Operations: Growth Record 1970 - 1975

The following table shows selected statistics highlighting the growth in natural gas operations over the past five years:

TABLE VII

CWNG & NUL - Combined Growth
1970 - 1975

	Customers At Year-End	Gas Sales Volume (BCF)	Approx. Rate Base ($ Mil.)	Net(1) Income ($'000)
1970	289,457	186.8	127	6,314
1971	303,253	206.6	133	7,223
1972	316,766	232.0	145	7,703
1973	335,494	240.5	155	7,146
1974	353,331	241.5	171	7,380
1975	373,254	254.6	189	9,581
Compound Annual Growth Rate				
5-Year: 1970 - 1975	5.2%	6.4%	8.3%	8.7%

Note: (1) Net income from operations after preferred dividends and before extraordinary items.

Growth in sales volume proceeded at a more rapid rate than growth in the number of customers during this five-year period, primarily because industrial sales to a relatively small number of customers rose at a significantly faster rate than residential sales. As is evident from the table, rate base growth in recent years exceeded 10% annually. This resulted from an acceleration in capital additions, particularly in the last two years.

TABLE VIII

Gas Operations - Capital Additions
1970 - 1975
($ Millions)

1970	12.3
1971	10.9
1972	16.9
1973	16.6
1974	27.0
1975	29.9

The rising trend in capital expenditures in the natural gas sector reflects several factors: the accelerating growth in the Alberta economy and in the demand for natural gas; major new transmission projects to connect additional gas supplies; more rapid extension of service in rural areas; the higher costs of gas storage due to rising wellhead prices; and, the inflationary trends in construction costs.

Gas Supplies

As of September 30, 1975, CU owned an estimated 808 BCF of gas and had 2,468 BCF under firm contract. In addition, 2,579 BCF are expected to be available for purchase in the future from fields where the estimated gas producing life exceeds the term of the existing gas purchase contracts. In total, these gas reserves of 5,855 BCF are equal to almost 22 years of supplies at the 1975 rate of consumption by CU of approximately 267 BCF.

It should be noted that the estimated recoverable reserves exclude volumes that CU may purchase under agreements with companies exporting gas from Alberta. The Company has agreements with all four of the major export companies which enable it to call upon the gas exporters for large quantities of both base-load and peak-load gas. During 1975, CU purchased 64 BCF, equal to 24% of its total requirements, under its contracts with the export companies. The balance of the 1975 supplies were obtained from oil fields, gas plants, and dry gas fields with over 40 BCF or 16% of the total supplied from the Company's own reserves.

Outlook for Natural Gas Operations

Gas Sales Volume

Gas sales volume is expected to rise 7% - 8% in 1976 after allowing for warmer than normal weather early in the year. CWNG is attaching two important new industrial customers this year, i.e., the fertilizer plants of Cominco Ltd. at Carseland, and the Canadian Fertilizers Ltd. plant at Medicine Hat. Both of these projects are expected to reach full load requirements during the fall of 1976 and therefore will fully impact on CU's gas sales only in 1977. The combined annual requirements of the two plants are approximately 100,000 MCF/d, representing an increase of 14% - 15% to CU's total 1975 sales volume.

Natural gas demand for the Province of Alberta as a whole is forecast to rise at a 10.8% annual rate over the next five years and at 6.8% annually over the next ten years. Since a significant portion of this growth represents feedstock requirements for the petrochemical plants in the form of ethane

extracted in gas processing plants, the sales volume of CU's gas subsidiaries will rise at a moderately slower rate than that projected for provincial demand. Over the next five years, CWNG's and CUL's combined gas sales are forecast to rise at an average compound rate of 8% - 9% annually, as compared with an actual growth of 6.4% annually during the 1970 - 1975 period.

Rate Base Expansion

Combined gross capital additions of CWNG and NUL are estimated at almost $41 million for 1976, as compared with just under $30 million in 1975. Their combined rate bases are estimated to rise to approximately $210 million in 1976 from $189 million in 1975, an increase of 11%.

During the 1977 - 1979 period, capital expenditures by the gas utilities should be approximately $45 - $50 million annually with a further increase to the $55 million level expected in 1980 - 1981. Rate base growth for the gas operations should average close to 13% annually during the five years from 1975 to 1980 based on projected capital expenditures and after deducting depreciation and increases in customers contributions to plant expansion.

Natural Gas Income

Combined net income from natural gas operations after preferred dividends and including non-utility income is estimated at approximately $12.6 million for 1976, up 31% from $9.6 million in 1975. Over the next five years, it is expected that the growth in net income from gas operations will tend to parallel the estimated rate base growth of approximately 13% annually.

ETHANE EXTRACTION PROJECT

CU and Dome Petroleum are in the process of finalizing an agreement to build a jointly owned gas processing plant designed to extract 20,600 barrels per day of ethane and 1,000 barrels per day of butane from NUL's main transmission pipelines delivering gas to the Edmonton area. The design capacity is 235,000 mcf/d raw gas intake and 203,000 mcf/d dry residue gas, indicating a consumption equivalent to 32,000 mcf/d to extract the ethane and butane. The residue gas will re-enter NUL's transmission system. The project is an integral part of the proposed major petrochemical complex in Alberta sponsored by Dome, Dow Chemical of Canada Limited ("Dow") and Alberta Gas Ethylene Company Limited ("AGECL"), presently a wholly-owned subsidiary of Alberta Gas Trunk Line. A portion of the ethane to be produced in the various extraction plants forming part of the complex will be converted into ethylene in Alberta at AGECL's plant near Red Deer. Surplus ethane will be exported from Alberta via the proposed Cochin Pipeline to be built by Dome and Dow and will be sold to the Columbia Natural Gas system at Greensprings, Ohio.

The capital cost of the CU/Dome ethane extraction plant is estimated at $40 million which is expected to be financed 75% debt and 25% common equity. Since CU will be an equal partner with Dome in the project, it is expected that CU will contribute approximately $5.0 million in common equity. The plant will be operated on a cost-of-service basis with long-term take-or-pay contracts. Following the pattern of other similar projects in Alberta, the cost of service will include provision for a 20% return on common equity.

CU's participation in ethane extraction represents its first significant diversification move. The extraction plant should be completed and commence operation by mid-1978. The whole petrochemical complex is scheduled to begin operations no later than January 1, 1979. The operation of the plant will provide CU with a new source of non-utility income generating an estimated net profit of approximately $1.0 million per year and will benefit NUL's existing gas customers through greater utilization of facilities and higher systems load factor.

In considering the past growth rates it is important to note that they were significantly enhanced by the earnings increases achieved in the single year 1975, primarily due to the improvement in regulatory procedures and the granting of higher allowable rates of return.

CONSOLIDATED RETURN ON EQUITY

The rate structure of CU's subsidiaries combine to produce a consolidated return on common equity which should enable the parent company to arrange new equity financing without causing dilution of per share equity or earnings, assuming continuation of the present regulatory treatment.

In the following table, which shows the consolidated return on average common equity earned in 1974 and 1975 together with an estimate for 1976, two adjustments are incorporated:

(1) The $1.25 convertible preferred shares are treated as part of the common equity. To date, approximately 90% of these shares have been converted; and

(2) An amount of $8.0 million representing the capitalized value of "Undertakings, Franchise and Gas Rights" is deducted from common equity since this item is not recognized as part of the rate base.

It should be noted also that net income shown includes unregulated, non-utility income but excludes extraordinary income.

TABLE X

Consolidated Return on Common Equity
($000's)

	1974	1975	1976E
Book Value of Common Equity			
- Beginning of Year	108,910	115,324	138,626
- End of Year	115,324	138,626	171,902
- Average	112,117	126,975	155,264
Net Income (Before dividends on the $1.25 Convertible Preferred)	14,696	20,491	24,573
Return on Average Equity	13.1%	16.1%	15.8%

The improvement in the return on equity achieved in 1975 on a consolidated basis reflects the higher returns allowed for each subsidiary. In addition, the natural gas operations benefitted from colder than normal weather in CWNG's service area. For 1976, giving effect to the above average temperatures prevailing earlier in the year, a moderately lower return on equity is forecasted.

CONSOLIDATED SOURCE AND APPLICATION OF FUNDS

The following table shows CU's source and application of funds for fiscal 1975 together with a forecast for 1976.

TABLE XI

CU - Consolidated

Source and Application of Funds 1975 & 1976E
($'000)

	1975	1976E
Net Earnings before Extraordinary Items	23,865	28,140
Non-cash Items, Principally Depreciation	14,729	16,500
	38,594	44,640
Increase in Notes Payable	5,197	12,100
Issue of Long-Term Debt	-	50,000
Issue of Preferred Shares	28,973	-
Issue of Common Shares	9,465	-
Increase Contributions for Extensions of Plant	9,916	11,500
Disposition of Property	3,943	4,000
Extraordinary Disposition of Property	2,572	-
	98,660	122,240
Purchase of Property, Plant & Equipment	82,981	86,800
Reduction in Long-Term Debt	13,467	4,976
Redemption of Preferred	1,200	1,200
Dividends Paid - Preferred	5,075	3,894
- Common	7,142	11,000
Other (net)	682	500
	110,547	108,370
Increase (Decrease) in Working Capital	(11,887)	13,870
Working Capital Deficit End of Year	19,400	5,530

The above forecast of 1976 source and application of funds will result in a higher debt ratio in the capitalization at year-end 1976 as compared with year-end 1975 unless further equity financing is undertaken. In view of the large capital expenditures projected for 1977 and the need for further senior financing next year, it is reasonable to expect that CU will issue additional common equity in preparation for its 1977 financing program.

For purposes of illustration, the following table shows a condensed summary of the actual capitalization at year-end 1975, the capitalization that would result from the 1976 source and application of funds estimate shown above, and a pro forma capitalization as at year-end 1976 giving effect to an assumed common equity issue in the amount of $20.0 million.

TABLE XII

CU - Consolidated Capitalization

	December 31					
	1975 Actual		1976E(1)		1976 Pro Forma(2)	
	($M)	(%)	($M)	(%)	($M)	(%)
Notes Payable and due Bank	51.4	11.8	63.5	12.6	44.7	8.9
Long-Term Debt	184.6	42.6	229.6	45.7	229.6	45.5
	236.0	54.4	293.1	58.3	274.3	54.4
Preferred Equity, Incl. Minority Interest	59.3	13.7	58.1	11.5	58.1	11.5
Common Equity Incl. $1.25 Pfd. (3)	138.6	31.9	151.9	30.2	171.9	34.1
	433.9	100.0	503.1	100.0	504.3	100.0

Notes: (1) Before common equity financing.
(2) After common equity financing.
(3) Excluding $8.0 million "Undertakings, Franchise and Gas Rights".

The estimated pro forma capitalization assumes that the net proceeds of approximately $18.8 million from a common equity issue would be applied to reduce notes payable. It is further assumed that issue expenses would be capitalized. The resulting capital structure would place CU in a strong position to undertake both debt and preferred equity financing in 1977 to facilitate its ongoing capital expansion.

RECOMMENDATION

The electric and gas operations of Canadian Utilities Limited are expected to expand rapidly in terms of rate base growth over the next several years due to the strong economic outlook in Alberta. Given the favourable regulatory climate in the province, this expansion will be translated into earnings per share growth. Utility earnings are expected to be further enhanced through diversification. With dividend payments anticipated to rise in line with earnings, CU common shares offer an attractive combination of income, safety, and appreciation prospects. It is noteworthy that share trading volume in CU, as evidenced in Appendix II, has increased significantly in the last year.

CONSOLIDATED FINANCIAL RESULTS

Financing Methods

Following the corporate restructuring, which became effective January 5, 1972 and which made CU a holding company and the parent of the operating subsidiaries, all of the external financial requirements of the organization have been arranged at the parent company level. One major purpose of the new method of financing was to facilitate the issuance of larger amounts of securities at less frequent intervals, in order to save financing expenses. This objective clearly has been accomplished. Prior to the restructuring, the largest single issue by any one of the affiliated companies was $15 million. Early in 1976, CU successfully sold a $50 million debenture issue, the amount of which reflected the new method of financing, the credit strength of the restructured company, and the growth taking place in recent years.

The upgrading in the credit ranking of CU's debt this year as a result of continuing earnings growth and an improved regulatory environment, should lead to further reductions in CU's debt financing costs. With regulations providing for an adequate return on equity and the common stock selling at a premium to book value, equity financing costs are also reduced.

Growth in Consolidated Earnings

The following table summarizes the earnings trend by subsidiary and on a consolidated basis for the period 1970 - 1975 and provides a forecast of results for 1976. The figures include non-utility income but exclude extraordinary items.

TABLE IX

CU - Earnings by Subsidiaries & Consolidated (1)
($'000)

	1970	1971	1972	1973	1974	1975	1976E
Net Operating Income							
Gas Operations - CWNG	2,897	3,405	4,156	3,586	3,361	5,155	6,000
- NUL	4,277	4,678	4,407	4,420	4,879	5,772	8,000
- Combined	7,174	8,083	8,563	8,006	8,240	10,927	14,000
Electric Operations - APL	4,618	6,038	7,415	7,467	7,623	13,567	15,000
Other	-	-	115	(238)	257	231	-
Total Operating Income	11,792	14,121	16,093	15,235	16,120	24,725	29,000
Less: Minority Interests (2)	1,191	1,226	962	860	860	860	860
CU Consolidated:							
Net Income Before Pfd. Divds.	10,601	12,895	15,131	14,375	15,260	23,865	28,140
Dividends Non-Conv. Pfd.	564	564	564	564	564	3,374	3,567
Net Income Before Convertible Preferred Dividends	10,037	12,331	14,567	13,811	14,696	20,491	24,573
Dividends $1.25 Conv. Pfd.	1,950	1,950	2,202	2,223	2,127	1,701	327
Net Income Avail. Common	8,087	10,381	12,365	11,588	12,479	18,790	24,246
Earnings Per Share - Basic	$0.90	$1.03	$1.23	$1.15	$1.24	$1.69	$1.71
- Fully-Dil.	$0.80	$0.91	$1.05	$0.99	$1.05	$1.45	$1.60

Notes: (1) A more detailed breakdown of consolidated income is shown in Appendix I.
(2) Represents minority interest in CWNG common (1970-1972) and preferred share dividends to minority shareholders.

APPENDIX I

CANADIAN UTILITIES LIMITED

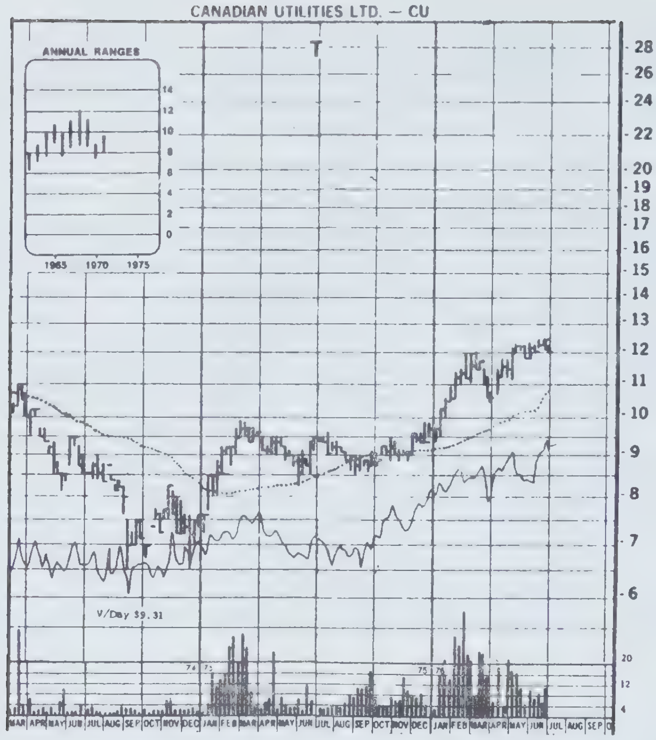
Summary of Earnings by Subsidiaries & Consolidation Adjustments (1)

	1970	1971	1972	1973	1974	1975	1976E
Alberta Power							
Net income before preferred dividends	4,618	6,038	7,415	7,467	7,623	13,567	15,000
Less: Preferred dividends paid to parent	591	591	591	591	591	3,021	3,117
Net income available common	4,027	5,447	6,824	6,876	7,032	10,546	11,883
Canadian Western Natural Gas							
Net income before preferred dividends	2,897	3,405	4,156	3,586	3,361	5,155	6,000
Less: Preferred dividends-paid to minority interests	440	440	440	440	440	440	440
-paid to parent	-	-	-	-	-	194	208
Net income available common	2,457	2,965	3,716	3,146	2,921	4,521	5,352
Northwestern Utilities							
Net income before preferred dividends	4,277	4,678	4,407	4,420	4,879	5,772	8,000
Less: Preferred dividends-paid to minority interests	420	420	420	420	420	420	420
-paid to parent	-	-	-	-	-	292	312
Net income available common	3,857	4,258	3,987	4,000	4,459	5,060	7,268
Combined Net Income Available Common							
Electric operations	4,027	5,447	6,824	6,876	7,032	10,546	11,883
Natural gas operations	6,314	7,223	7,703	7,146	7,380	9,581	12,620
Total	10,341	12,670	14,527	14,022	14,412	20,127	24,503
Consolidation Adjustments							
Preferred dividends received by parent	591	591	591	591	591	3,507	3,637
Minority interest CWNG common	(331)	(366)	(102)	-	-	-	-
Other adjustments upon consolidation	-	-	115	(238)	257	231	-
	260	225	604	353	848	3,738	3,637
Canadian Utilities							
Consolidated net income before preferred dividends	10,601	12,895	15,131	14,375	15,260	23,865	28,140
Parent company preferred dividends - non-convertible	564	564	564	564	564	3,374	3,567
Net income before dividends $1.25 convertible preferred	10,037	12,331	14,567	13,811	14,696	20,491	24,573
Dividends $1.25 convertible preferred	1,950	1,950	2,202	2,223	2,217	1,701	327
Consolidated net income available common before extraordinary items	8,087	10,381	12,365	11,588	12,479	18,790	24,246
Earnings per share before extraordinary items							
Basic	$0.90	$1.03	$1.23	$1.15	$1.24	$1.69	$1.71
Fully-Diluted	0.80	0.91	1.05	0.99	1.05	1.45	1.60

(1) Including non-utility income and excluding extraordinary income.

APPENDIX II

CANADIAN UTILITIES LTD. — CU



Source: "Canadian Industrial Stock Charts"
Independent Survey Co. Ltd., July, 1976.

CU Common Shares - Trading Volume T.S.E.

	1974	1975	1976
January	16,200	49,100	85,300
February	6,000	87,500	101,600
March	37,400	71,700	64,100
April	10,900	36,000	59,300
May	19,300	15,000	40,200
June	5,700	23,300	36,200
July	6,300	16,100	
August	5,600	22,200	
September	8,300	48,800	
October	6,100	24,400	
November	13,300	36,000	
December	30,900	30,300	
	166,000	460,400	386,700
Avg. Monthly Volume	13,800	38,400	64,450

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contracting of gas for use within the province has been constricted by exporters who have tied up contract volumes substantially in excess of amounts permitted for export. The supplementary test will involve a determination of the amount of gas actually available for contract.

The quarterly dividend on common shares of 18.5 cents per share is payable August 31 to holders of record on August 13, 1976.

Robert F. Calman, Executive Vice President of IU International, was elected as a new member of CU's Board of Directors at the company's annual meeting of shareholders on April 23.

E. W. KING
President

J. E. MAYBIN
Chairman

July 23rd, 1976

CANADIAN UTILITIES LIMITED

and subsidiary companies

Alberta Power Limited and subsidiaries
Canadian Western Natural Gas Company Limited
Northwestern Utilities Limited and subsidiary

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Edmonton, Alberta, Canada T5J 2V6
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Toronto, Ontario, Canada M5K 1H1
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interim report

Second Quarter June 30 1976

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CANADIAN UTILITIES LIMITED

CONSOLIDATED STATEMENT OF EARNINGS

(in thousands)

	3 Months Ended June 30		6 Months Ended June 30	
	1976	1975	1976	1975
Natural gas revenues	$44,791	$27,338	$111,628	$62,981
Electric revenues	18,961	13,240	39,485	27,660
	63,752	40,578	151,113	90,641
Operating expenses				
Natural gas supply	26,108	11,568	61,292	27,585
Operating and maintenance	17,687	13,044	34,023	25,553
Taxes — other than income	3,668	2,392	9,038	5,524
Depreciation	3,588	3,187	8,357	7,395
	51,051	30,191	112,710	66,057
Operating income	12,701	10,387	38,403	24,584
Other income				
Interest capitalized during construction	359	1,105	667	1,946
Interest and dividends	273	70	514	129
Gain on purchase of long-term debt	245	169	365	197
Miscellaneous	350	(89)	409	32
	1,227	1,255	1,955	2,304
	13,928	11,642	40,358	26,888
Income deductions				
Interest on long-term debt	5,087	3,875	9,678	7,769
Interest on loans from parent and affiliated companies	67	65	131	130
Other interest	180	752	696	1,499
Amortization of debt and share expenses	167	74	248	145
	5,501	4,766	10,753	9,543
	8,427	6,876	29,605	17,345
Income taxes	2,200	1,867	9,213	4,458
	6,227	5,009	20,392	12,887
Minority interests	214	214	430	430
Net earnings	$ 6,013	$ 4,795	$ 19,962	$12,457
Earnings — dollars per common share				
Fully diluted	$ .34	$ .27	$1.19	$ .77
Basic	$ .35	$ .32	$1.26	$ .96

Note 1: The interim figures in this report are unaudited.

Note 2: Fully diluted earnings per share assume exercise of warrants and conversion of the second preferred shares at the beginning of the year.

Note 3: There were 14,313,648 common shares outstanding on June 30, 1976 compared with 10,189,496 a year earlier.

Note 4: The natural gas supply expense is net of the Alberta government rebate of $9,926 in the quarter ended June 30, 1976, ($7,107 in quarter ended June 30, 1975) and $32,332 in the six months ended June 30, 1976, ($25,769 in six months ended June 30, 1975).

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

(in thousands)

	3 Months Ended June 30		6 Months Ended June 30	
	1976	1975	1976	1975
Sources of working capital				
Net earnings	$ 6,013	$ 4,795	$ 19,962	$12,457
Add non-cash items, principally depreciation	3,885	3,290	9,171	7,709
Provided from operations	9,898	8,085	29,133	20,166
Increase in notes payable	18,350	13,000	—	3,772
Issue of long-term debt	(4)	—	48,996	—
Issue of preferred shares	—	—	—	29,020
Issue of common shares	522	927	1,153	1,140
Increase in contributions for extension to plant	451	1,054	2,298	1,694
Disposition of property, plant and equipment	168	155	2,710	194
Amount payable under coal leases	4,000	—	4,000	—
Net proceeds under Natural Gas Pricing Agreement Act	524	—	1,103	—
	33,909	23,221	89,393	55,986
Uses of working capital				
Purchase of property, plant and equipment	24,398	18,960	38,007	36,600
Net gas stored	3,403	844	1,796	(475)
Reduction in notes payable	—	—	28,925	—
Reduction in long-term debt	1,494	10,925	3,244	12,587
Redemption of preferred shares	1,200	1,200	1,200	1,200
Dividends — preferred	825	1,200	1,808	2,642
— common	2,644	1,579	5,280	3,141
Conversion of $1.25 preferred shares	521	927	1,152	1,140
Increase in deferred expenses	153	402	291	613
Other	136	(93)	36	(112)
	34,774	35,944	81,739	57,336
Increase (decrease) in working capital	$ (865)	$(12,723)	$ 7,654	$ (1,350)

TO THE SHAREHOLDERS

Net earnings per common share for the six months ended June 30, 1976 were $1.19, compared with 77 cents in the corresponding period last year. Second quarter earnings this year were 34 cents a share compared with 27 cents in 1975.

It should be noted that comparisons of earnings and revenues with the previous year are distorted by the timing of applications to, and approvals from, the Alberta Public Utilities Board (PUB) for rate adjustments. New interim rates are designed to yield sufficient revenues to provide a fair return for the full fiscal year. Since the company's gas utilities entered 1976 at new rates awarded late in 1975, it is difficult to make a meaningful comparison with the first half of 1975. It is not expected that the rise in earnings experienced in the first six months of 1975 will continue on the same scale for the balalnce of the year.

Natural gas revenues were $111,628,000 in the six months under review, substantially higher than last year, mainly for the reason outlined above. Sales volume was 144.1 billion cubic feet, relatively unchanged from the year earlier. Taking into account weather variations between the periods, this figure represents a basic market growth of six per cent.

Electric revenues were $39,485,000, also up significantly over 1975. Electric energy sales of 1,134.6 million kilowatt hours were eight per cent higher than the previous year.

The PUB approved new interim rates in the second quarter for both gas and electric operations. New rates are required primarily to cover an April increase from 28 cents to 56 cents in the provincial support price for natural gas. (The provincial government subsidizes eligible Alberta consumers by an amount equal to the difference between the field price and the support price.)

A decision on a 1975 rate application by Canadian Western Natural Gas Company Limited was received in July, but Canadian Western is appealing certain aspects of the decision. The PUB has agreed to a review of the case.

Public hearings are proceeding on the remaining 1975 and the 1976 rate applications of the company's three Alberta regulated subsidiaries: Alberta Power Limited, Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited.

Alternatives are being evaluated for the development of new electric generating capacity in Alberta following the provincial government's refusal to pay the Dodds-Roundhill thermal electric project proposed by Calgary Power Limited and Can Pac Minerals Limited. It is likely that the coal deposits at Sheerness, south of the cancelled site and in Alberta Power Limited's service territory, will be developed earlier than previously planned. As a member of the province's Electric Utility Planning Council, Alberta Power has already conducted studies in preparation for development at Sheerness. Accelerated economic activity would appear to be in store for this area of the province.

There has not been sufficient time to assess the full impact of the Alberta government's recently announced coal policy; however, it is clear that the policy, which is intended to safeguard Alberta's future requirements, will ensure Alberta utilities' access to ample supplies of plain coal for electricity generation.

The town of Fort McMurray and surrounding area was connected to the provincial power grid upon completion of a 207-mile transmission line constructed by Alberta Power Limited. APL is also providing electric power during construction at the Syncrude oil sands project.

In response to representations by the company's gas utilities, the Alberta Energy Resources Conservation Board has adopted a supplementary test in its method of determining the amount of gas surplus to provincial requirements, and therefore available for export. The utilities have found that their direct